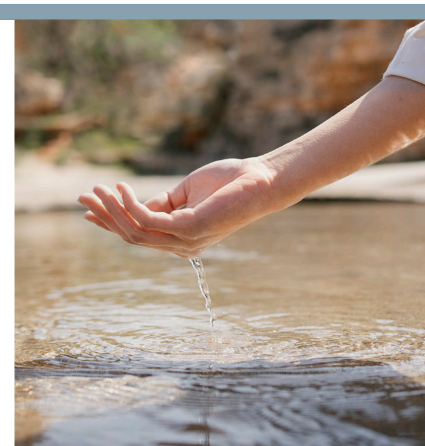
Ground Water Protection Council

State Oil and Natural Gas Regulations Designed to Protect Water Resources





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Preface

This report was developed by the Ground Water Protection Council (GWPC) as an update to the 2014 and 2017 editions of the publication, "*State Oil and Natural Gas Regulations Designed to Protect Water Resources*."[1] The purpose of this and earlier studies, based on a review of 27 state oil and gas agencies, was to describe selected areas and related elements of state oil and gas regulations designed to protect water resources and to generally describe the rule language and agency approaches related to those areas. This update describes the considerable progress that agencies continue to make as they update their oil and gas regulatory programs.

The GWPC is the national association of state agencies that strive to protect and conserve our nation's groundwater resources. The GWPC provides a forum for stakeholders including state, federal and local government officials, environmental non-governmental organizations, and representatives of the regulated industry to discuss emerging issues, technological advancements, the latest scientific research, recommended management practices, and regulatory responses to improve protection of groundwater resources.

State oil and gas regulators place great emphasis on protecting water resources from adverse impacts that can occur during oil and natural gas exploration and production (E&P) activities. The GWPC believes that regulation of oil and gas field activities is best managed at the state level where regional and local conditions and best applied practices are understood, and where regulations can be tailored to fit those conditions. While there are aspects of oil and gas regulation that occur at the local and federal government level, in the vast majority of instances the greatest experience, knowledge, and information necessary to regulate effectively resides with state regulatory agencies.

It is important to note that this review covers only state oil and gas agency regulations. We recognize there are states in which other agencies such as state environmental protection/ resource conservation agencies or divisions, state health agencies, or other agencies may implement regulations that cover some of the elements listed. For example, in Alaska several elements such as pits, tanks, produced water transport; some types of waste disposal and spill management are regulated by the Alaska Department of Environmental Conservation and/or the Department of Transportation and/or other agencies rather than by the Alaska Oil and Gas Conservation Commission. There are also cases, such as in Ohio, where regulatory requirements are specified not only in the Ohio Administrative Code (rule) but also in the Ohio Revised Code (the legislative statute governing oil and gas activity). While we recognize these dichotomies of

[1] Ground Water Protection Council, State Oil and Natural Gas Regulations Designed to Protect Water Resources (Apr. 2009, April 2014), *available at* https://www.gwpc.org/research/.

regulation, this report does not attempt to capture all potential state regulatory structures for every element due to the multiplicity and variability of agencies across numerous states. Consequently, our review focuses on state oil and gas agency regulations (rules) only because these comprise the primary regulatory framework for managing oil and gas E&P in the majority of states. Although this report covers a significant portion of oil and gas regulation in the reviewed states, it cannot address all regulatory management scenarios. Therefore, the information in this report does not represent the full scope of state oil and gas regulation.

We would like to thank the following state oil and gas regulatory agencies for their assistance:

Alabama State Oil and Gas Board
Alaska Oil and Gas Conservation Commission
Arkansas Oil and Gas Commission
California Department of Conservation, Geologic Energy Management Division
Colorado Oil and Gas Conservation Commission
Florida Department of Environmental Protection, Oil and Gas Program
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 Energy and Environment Cabinet, Division of Oil and Gas
Louisiana Department of Natural Resources, Office of Conservation
Michigan Department of Environment, Great Lakes and Energy, Office of Oil, Gas and Minerals
Mississippi State Oil and Gas Board
Montana Department of Natural Resources & Conservation, Board of Oil and Gas Conservation
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, Division of Oil and Gas Resources
Oklahoma Corporation Commission, Oil and Gas Conservation Division
Pennsylvania Department of Environmental Protection, Office of Oil and Gas Management
South Dakota Department of Agriculture 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 Energy, Gas & Oil Division
West Virginia Department of Environmental Protection, Office of Oil and Gas
Wyoming Oil and Gas Conservation Commission

The views expressed in this report, as well as any suggested "Considerations," are those of the GWPC, in general, and do not necessarily reflect those of any particular state. Further, the considerations in this report should not be construed as offering "Best Practices," as each situation is different and a uniform practice for any element may not be appropriate or desirable in every case. Any errors or omissions concerning state rules or procedures are the responsibility of the GWPC and not an individual state. State regulatory programs are significantly more detailed and comprehensive than could possibly be represented in this summary report. Consequently, we strongly recommend the reader contact individual state oil and gas agencies to obtain information about specific state oil and gas requirements. We hope you will find this report informative and useful.

This report was partially funded through the Ground Water Research & Education Foundation.

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Chapter 1: Report Summary

Figure 1-1 Typical rotary drilling operation- Source, Southwestern Energy

Although current uncertainties in the fossil energy sector exist, there was an overall increase in activity over the past two years. Also, the emphasis on improved groundwater protection laws and regulations governing oil and natural gas production has continued. It is critical to maintain comprehensive and effective regulations. State regulatory strategies differ in response to unique local circumstances and characteristics. Over time, they evolve to address public concerns about the safety and environmental impact of oil and gas development, as well as rapidly changing technologies, new field discoveries, revised leading operational practices, internal and external reviews, and regulatory experience.

The GWPC prepared this report to help equip regulators and policymakers with pertinent data and observations to consider when evaluating and revising rules in their agencies. It includes an overview of regulations in 27 state oil and gas agencies as of January 1, 2021, a discussion of how rules have evolved since the previous review, and considerations for regulators and policymakers derived from leading practices adopted or proposed in various agencies.

The report also builds on previous discussions of several emerging issues that merit more detailed consideration in future state regulatory evaluations. With regard to alternate use of produced water, for example, these include continued investigation into the near-term feasibility of alternative disposal options (like evaporation) and technical and regulatory advancements that support expansion of in-field recycling by the oil and gas industry. Other significant issues related to groundwater protection include: wellpad construction, stormwater management, annular pressure monitoring, well and surface facility legacy issues, reuse of produced water, both within and outside of oil and gas operations, and spill management and cleanup.

This report highlights several practices adopted by oil and gas regulating agencies to enhance transparency, efficiency, and effectiveness in regulatory implementation. Successful groundwater protection requires not only an appropriate framework of laws and rules, but also sound regulatory practices and programs. State agencies use programmatic tools and documents to promote consistent implementation, coordination, enforcement, and documentation of state rules. These include tools such as forms, formal and informal guidance, policies and procedures, and data management systems like the Risk Based Data Management System (RBDMS) developed on behalf of state agencies by the GWPC. Although this report will discuss some associated elements of regulation such as data management, the primary thrust of the report is promulgated regulations (rules).The complexities of covering the myriad policies and procedures developed by state agencies would require a more comprehensive evaluation.

Since the 2017 report, agencies have made measurable progress in some of the areas tracked by this report. As oil and gas E&P has been developed around the country and especially in areas where unconventional resources are present, the public has expressed concern about the safety and environmental impact of oil and gas development. Oil and gas agencies address these concerns by proactively conducting internal reviews and updating their regulations to respond to changes in technology and practices. Some notable updates include requirements for management of hydraulic fracturing operations, chemical disclosure of hydraulic fracturing fluids, enhancements to mechanical integrity (MI) testing, improved pit siting and lining requirements, and advances in data management. States also use external program reviews conducted by 3rd party organizations to evaluate their current regulations and provide suggestions for revision. When agencies update their rules, consideration is often given to focusing on areas that will increase protection for water resources including issues covered here such as well integrity, surface fluid management, and cleanup standards for spills. Interagency and interstate coordination of activity is also increasingly critical, alongside the need for data integration between disparate data systems, which will lead to better data analysis capability and increase transparency.

Overall, state oil and natural gas regulatory agencies are diligent in addressing the technological, legal, and practical changes that occur in oil and gas E&P. By employing highly trained, experienced staff and implementing rules designed to protect water resources, agencies show their commitment to continuous improvement with an aim toward assuring water availability and sustainability.

State Regulations Highlights and Considerations

State oil and gas regulatory frameworks related to groundwater protection are evolving steadily. The state of play in oil and gas regulation covers numerous areas of interest. Each of these areas contains specific elements that typify the current status of regulatory management as of January 1, 2021.

Permitting

All 27 oil and gas agencies require permits for the drilling, and operation of oil and gas related wells. Twenty-six also require a permit to re-drill or deepen an existing well and 22 require a permit for well workovers. Fewer oil and gas agencies (eight) require a separate permit to construct a well pad and (six) require a permit for stormwater management on a wellsite. However, regulators often consider well pad construction activities and stormwater management during the process of reviewing the drilling permit, and some agencies even require pre-drill site inspections that can be used to evaluate potential specific site construction and stormwater management activities.

Considerations:

- For states where topography, weather patterns, or other factors pose challenges for well pad construction, requirements that mitigate those issues.

Hydraulic Fracturing

Perhaps the most significant trend in the area of hydraulic fracturing relates to the notice requirements prior to conducting hydraulic fracturing operations. In 2014 only six agencies had a notification requirement for this activity. By January 1, 2016, the number had risen to 15. As of this report 16 agencies require prior notice. This represents a substantial increase between 2014 and January 2021. There was also a significant increase in the number of agencies requiring adjacent water well testing (from four to twelve between 2014 and 2021).

Considerations:

- Mechanical Integrity Testing requirements prior to well stimulation;
- Monitoring and reporting requirements during well stimulation, and suspension of well stimulation when mechanical or formation integrity is compromised;
- Analysis of confining zone(s) and “Area of Review” style analysis of near wellbore geology to mitigate risk of conduits transmitting hydraulic fracturing fluids;
- Defining the meaning of simultaneous operations (SimOPS) relative to hydraulic fracturing; and
- Reporting volumes of water used by type (e.g., Produced water, groundwater, fresh water etc…).

Well Integrity

Providing assurances that wells will not provide critical flow pathways for the migration of fluids or gases from downhole to the surface or into groundwater is of paramount importance. Proper well construction and evaluation techniques can demonstrate the effectiveness of the well in preventing migration. One of the most critical well construction phases is the proper setting and cementing of the surface casing string. Twenty-six of the agencies reviewed specify the setting of surface casing below the deepest protected groundwater zone. One agency uses a table that specifies the surface casing setting depth based on the total depth of the well. It was not possible to determine from the regulation whether or not this would result in setting surface casing below the deepest protected groundwater. Regardless, all 27 agencies specify bottom to top cementing; although one agency provided for such cementing based on downhole specific conditions. Thirteen agencies require surface casing to be pressure tested prior to drill out and eight require the use of casing centralizers on the surface casing string. With respect to general casing standards, 14 agencies have specific standards including nine that require the use of API standards for casing and seven with standards on the use of used or re-conditioned casing.

Considerations:

None of the policies above are universally applied. Regardless, additional aspects of well integrity for wider consideration might include:

- Comprehensive well integrity testing during construction, especially Formation Integrity Testing (or "shoe" testing) prior to drill out;
- Centralization standards for production/long string;
- Isolation of flow zones capable of over-pressurizing an annulus and corrosive zones
- Providing standards for reconditioned casing;
- Specifying mix-water quality standards and requirements for free water content in cement;
- Reporting of "kicks" during drilling to ensure well control oversight and to establish a better understanding of potential over-pressurized zones; and
- Standards for annular space minimums between casing strings and between strings and formation

Temporary Abandonment

Twenty-six agencies allow operators to temporarily abandon (TA) or idle wells with 22 of these requiring a prior authorization before a well can be placed in TA status. Twenty-six agencies also allow temporary abandonment status to be extended beyond an initial time period and 17 require either a casing pressure test or specific well construction before the TA period can be extended. Fifteen agencies place a total limit on the time a well may remain in TA status.

Consideration:

- Monitoring of wells in TA status to ensure they maintain mechanical integrity; and
- Establishing a maximum time duration within which a well may remain in TA status.

Production Operations

There are three specific aspects of operations reviewed for this report. All three are related to monitoring or inspections by the operator of particular elements. The first is the monitoring of the bradenhead fitting on wells to look for changes in pressure which might indicate a loss of integrity. As of this review, seven agencies require operators to monitor the bradenhead (an increase of 43 percent since 2017). The second is the inspection of piping, valves, and flowlines to look for signs of leakage. Six agencies require these types of operator inspections (an increase of 33 percent since 2017). The last element reviewed was a requirement for inspections of other appurtenances such as tanks, well heater/treaters, oil/water separators and similar equipment. The purpose of these inspections as with inspections of piping, valves and flowlines is to look for signs of failure or leakage. As of January 1, 2021, six agencies require this type of operator inspection (an increase of 50 percent since 2017).

Consideration:

- Bradenhead monitoring requirements to facilitate lifetime well integrity management; and
- Requirements for operator inspections of piping, valves, flow lines and other appurtenances during operations.

Storage in Pits

Although pits are used for a number of different purposes, this report focuses on the most commonly used pits (drilling and produced water storage). The elements reviewed for these pits are related to their construction, operation, monitoring, and closure. As of this report, 25 agencies had specific requirements concerning drilling pits while 19 agencies regulated produced water storage pits, including four agencies that banned the use of such pits. Six agencies also had separate regulations governing the use of centralized storage pits. With respect to requiring a prior authorization to construct and operate pits, 15 agencies require such authorizations for drilling pits while 19 require prior authorization for produced water storage pits. In ten agencies drilling pits require a siting setback from surface water with 11 agencies limiting the siting of drilling and produced water storage pits within the 100-year floodplain or in a floodway. Certain construction requirements varied depending upon pit type. For example, 14 agencies require a liner for drilling pits and 18 agencies require a liner for produced water storage pits. Fifteen agencies also specify liner competency standards for both types of pits (an increase of 13 percent since 2017). Regarding the duration of use, 20 agencies have a usage time limit for drilling pits and 13 limit the usage time for produced water storage pits. Finally, 12 agencies specify that upon closure the site must be returned to its condition prior to use for drilling pits while eight have the same specification for produced water storage pits.

Considerations:

- Requirements for siting, design, construction, operations, and closure of pits;
- Competency standards for liners;
- Inspections prior to use and during operations; and
- Leak detection requirements.

Storage in Tanks

As with previous reports the regulation of above ground storage tanks is limited and remains an area of concern. However, as of this report six agencies require a prior authorization to construct and operate tanks (an increase of 66 percent since 2017) and seven had some design and construction standards for tanks. Further, seven agencies have some siting or setback requirements (an increase of 29 percent since 2017). On another positive note the number of agencies requiring a secondary containment system for tanks increased from 17 to 22 between 2017 and 2021, with 18 of these requiring ongoing inspections of the containment area.

Considerations:

- Requirements should address siting, design, construction, operations, and closure of tanks; and
- Tank material compatible with stored fluids.

Well Plugging

The effective plugging of oil and gas wells is critically important to the protection of groundwater. Plugging involves the placement of cement and other materials at strategic locations in a manner designed to prevent the migration of fluids and gases from producing or injection zones into protected groundwater zones. In this regard 24 of the agencies reviewed require placement of cement plugs above producing formations and 19 also require the placement of cement plugs across all protected groundwater zones. The combination of production zone plugs, and groundwater plugs ensures that protected groundwater is isolated from deeper production or injection zones. Further, 21 agencies require the submission of a plugging plan prior to plugging so that the agency can evaluate the proposed plugging details for adequacy and to assure they meet regulatory requirements. Finally, all 27 agencies require operators to submit a post plugging report for agency review.

Consideration:

- Cement placement across all protected water zones;
- Witnessing of well plugging operations by agency representatives; and
- Tagging of plugs where needed to assure proper placement.

Transportation of Produced Water for Disposal by Truck or Pipeline

The transportation of produced water is one of the regulatory elements reviewed that is sometimes regulated by multiple agencies within state government. As a consequence, the number of oil and gas agencies regulating transportation practices does not reflect the totality of regulatory control. That said, the review of oil and gas agency regulations indicates that 11 oil and gas agencies require a prior authorization for the transport of produced water. Four agencies regulate pipeline transport while nine regulate truck transport. Regardless of the transportation method, 13 agencies require operators to utilize manifests or trip tickets to track the movement of produced water (an increase of 23 percent since 2017). Additionally, 16 agencies also require operators to report the final disposition of produced water (an increase of 19 percent since 2017).

Considerations:

- Permitting or licensing of produced water transporters and the recording of produced water volumes transported off-site; and
- Tracking and reporting of final disposition.

Produced Water Reuse for Oil & Gas E&P

The reuse of produced water in the oilfield has continually increased over the past decade. The bulk of this reuse can be attributed to the use of produced water as a carrier fluid for high volume horizontal hydraulic fracturing. In the latest update of figures commissioned by the GWPC (2017), beneficial reuse of produced water for oil and gas operations (other than enhanced recovery) remained small at about 1.4 percent.[2]. Regardless, this is more than twice the amount used in oil and gas operations in 2015. Also, there are new regulations being adopted such as one in New Mexico that regulates the transfer of water from the oilfield to outside, non-oilfield uses. However, it is only in the past few years that produced water with higher levels of Total Dissolved Solids (TDS) has been acceptable in the hydraulic fracturing process. Further, the volumes of water being used for high volume hydraulic fracturing have grown significantly. Consequently, the total volumes of produced water re-used in the oilfield is likely to continue to grow and contribute to greater overall beneficial reuse in the coming years provided the upward trend in the use of hydraulic fracturing using large water volumes continues. Although using produced water in the drilling of oil and gas wells is a customary practice, certain restrictions on this use have been gaining traction. For example, the review of agency regulations indicates that 11 agencies prohibit the use of produced water during the drilling of the surface casing portion of a well to protect groundwater resources.

Considerations:

- Chemical characterization and management of side streams;

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[2] Veil, John U.S. Produced Water Volumes and Management Practices in 2017, GWPC, February 2020, 137 pp., https://www.gwpc.org/sites/gwpc/uploads/documents/publications/pw_report_2017___final.pdf

- Regulation of use of produced water for uses in the oilfield other than well stimulation; and
- Siting, design, construction, operations, and closure standards for produced water pipelines.

Exempt Waste Disposition

Similar to produced water transport, the management of exempt waste is often regulated by multiple agencies within a state. In 21 states, the oil and gas agency has some regulatory control over on-site disposal of exempt waste, and 15 oil and gas agencies regulate land or road application of produced water (an increase of 20 percent since 2017). Eleven agencies regulate the application of tank bottoms to roads or lands. Eight agencies prohibit the land application of produced water, and six prohibit land application of tank bottoms.

Consideration:

- Manifests for off-site disposal where appropriate.

Spill Response

The management of spills from oilfield operations also commonly utilizes a multi-agency approach. For example, response to a spill may involve multiple agencies depending upon several factors including the location, nature, volume, and media affected by a spill. Twenty-five oil and gas agencies require some spills to be initially reported to the agency, though 19 agencies have a volume threshold for reporting. Twenty-three agencies also require a detailed follow-up notice be submitted to the agency within a specified time. Twenty-three oil and gas agencies also have spill remediation jurisdiction, and 13 have some quantifiable cleanup standards. (an increase of 23 percent since 2017).

Considerations:

- Clean-up standards that are measurable and appropriate for the characteristics of the material spilled and the media impacted; and
- Follow up notification details to improve performance.

Chapter 2: Background, Purpose, and Scope

Background

As stated in previous reports, regulating is the process used to manage an activity under the authority of a law or rule and consists of two principal parts: rules and programs. Rules are the set of instructions or requirements that govern an activity. Programs are the means by which these instructions or requirements are enforced. The boxes below describe how rules and programs are linked to create the regulatory framework.

Rules

Rules can be either prescriptive or proscriptive. Prescriptive rules define what must be done while proscriptive rules define what must not be done. For example, a prescriptive rule might read "The operator shall install a ¼-inch NPT fitting on the casing tubing annulus of each Class II well," while a proscriptive rule might say "Pits shall not be located within the boundary of the 100 year flood zone." Rules can also be performance based or descriptive in type. For example, a performance based rule might say "The operator must use an amount of cement sufficient to protect all fresh groundwater zones," while a descriptive rule might say "The operator must use an amount of cement calculated to circulate to the surface behind the casing plus a 10 percent overage." Each type of rule plays a key role in the regulatory process. Performance based rules allow the regulatory agency and the regulated community to define requirements based on site-specific conditions. As such they can often provide a more appropriate response to a unique set of conditions. Descriptive rules are less flexible but do not require as much interpretation and, as such, tend to be easier to follow.

Programs

In state oil and gas programs, application of the rules is typically overseen by a governing body such as a commission, board, or division. In some cases, these bodies consist of people appointed by the governor of a state, while in other cases independently elected commissioners or board members may have the authority to apply the regulations. Day-to-day operations are typically run by an oil and gas agency (division) that includes directors, managers, geologists, engineers, technicians, field inspectors, administrative staff, and legal staff. The staff is charged with the responsibility of ensuring the regulated community is following state rules. Regulatory agencies accomplish this by conducting administrative and technical reviews of permit applications, witnessing field operations, performing field inspections, conducting meetings and hearings and, where necessary, taking formal enforcement action to achieve compliance.

Purpose

In 2009, 2014, and 2017 the GWPC published editions of this report entitled "*State Oil and Natural Gas Regulations Designed to Protect Water Resources*."[3] The purpose of these reports was to discuss the areas and related elements of state oil and gas regulations that protect water and to describe the regulatory language embodied in oil and gas agency regulations governing those areas and elements. The reports included a list of suggested actions for consideration by state policymakers as they engage in continuous improvement of their regulatory frameworks.

For this update, the GWPC builds on the analytical work previously conducted and documents the intervening enhancements in regulatory programs made by many agencies.

Scope and Methodology

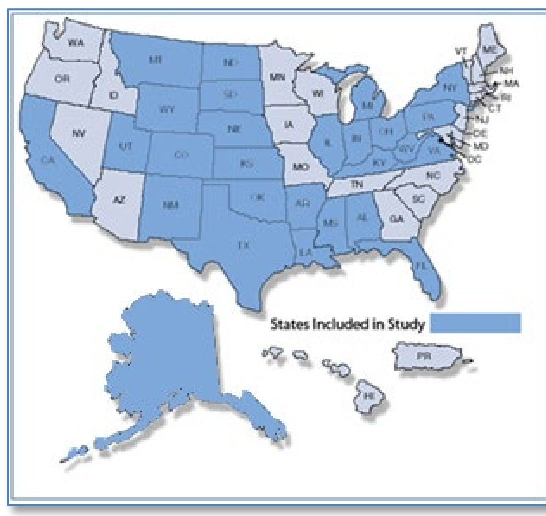

Figure 2-1 Map of Selected Included Oil and Gas Agencies

For this updated report, the GWPC reviewed the regulations of 27 oil and gas regulatory agencies in major oil and gas producing states as of January 1, 2021(Figure 2-1), modifying and adding areas, and related elements to facilitate an expanded and appropriately comparative review. The 2009, 2014, and 2017 reports included a variety of considerations for state policymakers and researchers. For this edition of the report several changes were made in the methodology used for evaluating regulatory requirements. In the 2017 report agencies were no longer counted for meeting an element if the language of the regulation provided for wide flexibility in applying the element. For the 2017 update the reviewers also applied a stricter standard on rule language and only accepted such language when it specifically applied the element. For example, in 2009 and 2014 an agency would have been counted for meeting an element even if application of the element were only done under specific circumstances. For the 2017 report, an element would be considered met only if it were applied statewide without the need for an agency determination. This change to the evaluation criteria was made in 2017 to normalize the criteria and take out as much regulatory subjectivity as possible. For this reason, many of the element numbers in the 2017 report differed from those in

[3] Ground Water Protection Council, State Oil and Natural Gas Regulations Designed to Protect Water Resources (2014), available at
https://www.gwpc.org/wp-content/uploads/2017/11/State_Regulations_Report_2017_Final.pdf

the 2009 and 2014 reports. This does not indicate agencies are lowering their regulatory requirements but rather, that the elements were more stringently reviewed. This is important because there are several elements where, even using the stricter review standard, the numbers increased. This indicates an even greater change in oil and gas regulation than would otherwise have been indicated. Another meaningful change in methodology was in the way many of the elements were worded. In the 2014 review a number of elements were measured against whether or not an agency "allowed" a practice. For the 2017 edition of the report a practice was not counted as allowed unless the agency had specific rules related to the use of the practice. This change was made to avoid the inference that a practice would automatically be allowed unless an agency prohibited it, and this resulted in numerous instances where an item would have been counted in 2014 but not in the 2017 report. All of these changes in methodology were carried forward into this 2021 report. Further, some elements were insufficiently detailed to allow for a useful evaluation. For example, the 2014 element "Does the rule place a limitation on the constituents of drilling fluid" was modified in 2017 to become "Does the rule place a limitation on the constituents of drilling fluids for surface casing," and expanded to include sub-elements as to whether or not the agency prohibited the use of oil based or produced water based drilling fluids. Because of the changes in review methodology such as those noted above, it was not possible to compare the numbers in the 2017 report to previous reports. However, the 2021 report contains numerous comparisons between specific element numbers from 2017 to 2021.

Discussion drafts, thought pieces, outside proposals submitted to agencies, and other non-official regulatory documents were not included in the study.

Appendix 4 shows the matrix of regulatory areas and related elements reviewed for this update. For some elements, this report presents comparisons between the 2017 and 2021 findings.

As with the 2009, 2014, and 2017 reports, each state's rules were compared to the elements within each regulatory area. A determination was made as to whether or not the state had a rule that addressed the element or elements. As noted previously, however, the evaluation criteria were modified to provide for a stricter interpretation of the rules in order to minimize subjectivity. After each state's rules were evaluated, the state was given an opportunity to review and comment on the findings and to provide updated information concerning their rules.

Comparison of Regulatory Areas Used in the 2009, 2014, 2017, and current reports

In conducting this update, GWPC used the same regulatory areas as the 2017 report to facilitate comparisons (Table 3-1).

2009 Areas	**2014 Areas**	**2017 Areas**	**2021 Areas**
Permitting	Permitting	Well and wellsite permitting	Well and wellsite permitting
Well construction	Well integrity	Well integrity	Well integrity
Hydraulic fracturing	Formation treatment, stimulation, or fracturing	Hydraulic fracturing	Hydraulic fracturing
	Production operations	Production operations	Production operations
Temporary abandonment	Temporary abandonment	Temporary abandonment	Temporary abandonment
Well plugging	Well plugging	Well plugging	Well plugging
Pits	Storage in pits	Storage in pits	Storage in pits
Tanks	Storage in tanks	Storage in tanks	Storage in tanks
	Transportation of produced water for disposal	Transportation of produced water by truck or pipeline for disposal	Transportation of produced water by truck or pipeline for disposal
	Produced water recycling and re-use	Produced water reuse for oil & gas E&P	Produced water reuse for oil & gas E&P
Waste handling and spills	Exempt waste disposal	Exempt waste disposition	Exempt waste disposition
	Spill response	Spill response	Spill response

Table 3-1 Areas Reviewed from 2009 to January 2016

Definitions of "protected groundwater" differ across the agencies surveyed, complicating the evaluation of state oil and gas rules, and preventing the use of a single precise term, such as Underground Source of Drinking Water (USDW), throughout this report. Therefore, this report uses the generic term "groundwater," defined as ***"water contained in geologic media which has been designated by a state as usable for domestic, industrial or municipal purposes or which is otherwise protected by state regulation."*** Differing state definitions of protected groundwater were the subject of a companion report published by the GWPC[4].

Finally, this update highlights emerging issues in the field of oil and gas regulation and discusses several topics critical to understanding a wider spectrum of state efforts to protect groundwater.

[4] Musick, Stephen P., Overview of Groundwater Protection Regulations in Oil and Gas States, GWPC, April 2014 PP. 11

It concludes with considerations for regulators, policymakers, and researchers, summarizing ideas on today's leading practices from agencies around the country related to issues agencies are likely to encounter in the near future.

Exclusions

In addition to state oil and gas agencies, other local, state, and federal agencies may exercise significant control over oil and gas activities. Time and resource constraints do not allow this report to account for interactions between the oil and gas agency and other local, state, and federal regulatory agencies, nor to catalog relevant regulations of these other agencies. Many of these agencies operate under a Memorandum of Agreement (MOA) or Understanding (MOU) with the state oil and gas agency to define jurisdictional boundaries. For example, the Railroad Commission of Texas has an MOU with the Texas Commission on Environmental Quality (TCEQ) relative to the intersections of agency jurisdiction (Appendix 8). Such agreements are commonplace in many agencies and reflect a coordinated approach designed to increase environmental protection and emergency response. In some western states agencies, the Bureau of Land Management (BLM) exercises substantial control over oil and gas E&P activities where the federal government or a tribal government is the primary landowner or mineral rights holder. In some cases, the state will defer to the BLM while in other cases there is a dual layer of regulatory control. In a 2012 survey of state oil and gas agencies, the GWPC found that 13 of 15 agencies issued a separate state permit for oil and gas wells on federal land.[5] (Appendix 7) In such cases it is not uncommon for the state and BLM to have an MOA or MOU. In some agencies there is a basic jurisdictional split between state agencies relative to the regulation of oil and gas activities. While uncommon, this type of jurisdictional split makes a complete understanding of all aspects of oil and gas regulation throughout the country more complex and challenging.

As with the previous versions of this report, Underground Injection Control (UIC) programs were not reviewed for this update. UIC regulation was excluded because on-site reviews of such programs are already conducted by the GWPC under the Class II UIC Peer Review process. Consequently, while the UIC program is discussed in the report as a produced water disposal method, this study does not address UICrelated issues such as induced seismicity and a comprehensive review of the UIC regulations and programs was not conducted[6].

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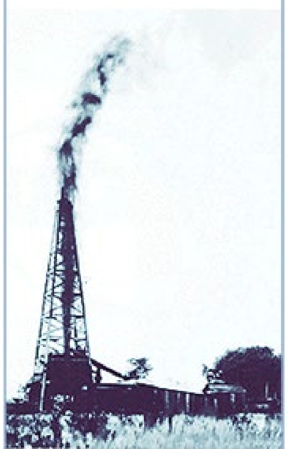
5 Survey of States Regarding Permitting on Federal Land, GWPC, 2012
6 https://www.gwpc.org/research/

Chapter 3: Evolution of Oil and Gas Regulation



Oil Well Circa 1870

Figure 3-1 Source, Unknown

The evolution of water and environmental resource protection regulations governing oil and gas exploration, production, and well abandonment "upstream" activities did not follow the same pattern as other waste-producing industries, including those related to oil refining and other "downstream" petroleum operations. Controls for preventing damage to air, water, land, and hydrocarbon resources from "downstream" operations were primarily developed in response to a series of federal pollution control acts passed by Congress between 1972 and 1990. In contrast, water protection measures related to the "upstream" (production) sector of the petroleum industry, covered in this study, were initiated much earlier in response to individual state statutes and regulations enacted after 1900.

A historical perspective reveals how, over time, state legislative bodies responded to increasing concerns by landowners, farmers, and municipal officials that oil field practices were contaminating water and land resources. It also shows how state oil and gas environmental regulations have been philosophically influenced by of the influx of federal environmental laws during the past forty-five years in some ways, but not in others.

Looking Forward: Drivers of Regulatory Development

State regulation of oil and natural gas E&P 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 state regulatory process. Regulation of oil and gas field activities is managed best at the level where regional and local conditions are understood and where rules can be tailored to fit the needs of the local environment. While some oil and gas production regulation does occur at the local and federal governmental level, on most issues the greatest experience, knowledge, and information necessary to regulate effectively rests with state regulatory agencies.

As captured in the first three versions of this report, state legislators and regulatory agencies from coast to coast have continued to write new laws, finalize, and propose regulations, and modify existing regulatory practices and programs to address pressing concerns of industry and the public alike. As this updated report documents, there has been continuous and significant regulatory improvement by state oil and gas agencies across the country over the past four years. As efforts increase to bring regulations up to date with rapidly changing technologies and other regulatory drivers continue to directly impact the industry, growth and change to state oil and gas regulatory programs is likely to continue. But what are the factors that drive the state regulatory update process?

Factors driving changes to rules and state regulatory programs include regulatory experience, routine internal review of existing rules, technological updates, public input, new field discoveries, revised best management practices, and internal and external reviews. To assure regulations are implemented as designed, some agencies like the Railroad Commission of Texas maintain online manuals (https://www.rrc.state.tx.us/oil-and-gas/publications-and-notices/manuals/) to assist operators with regulatory compliance. In Texas these include an Oil and Gas Procedure Manual, a manual on Injection Storage and a manual on Surface Waste Management which contains specifications for water protection relative to oil and gas operations including:

- A list of applicable rules such as:
  - Statewide Rule 8: Water Protection[7];
  - Statewide Rule 91: Cleanup of Soil Contaminated by a Crude Oil Spill; and
  - 16 Texas Administrative Code Chapter 4, Subchapter F, Oil and Gas NORM

Regulatory experience and activity is one of the primary drivers of regulatory reform. Based on the knowledge of past problems and investigative findings, regulatory agencies will often define new boundaries for regulatory management. A review of the history of oil and gas activity can be used to evaluate the effectiveness of current regulation and to provide the basis for regulatory change. For example, although Texas banned them in 1969, in the 1970s the use of evaporation pits was still not an uncommon practice. As evidence of shallow subsurface groundwater contamination near such pits became evident, there was a call for more stringent regulation. This led to the banning of evaporation pits in some agencies and the lining of these pits elsewhere.

The public has also played a significant role in the development of regulations. By providing input on proposed rules, the public has affected the regulatory development process in a meaningful and direct way.

External reviews of state programs conducted by organizations such as IOGCC and GWPC are also a part of the regulatory review process.

Further, efforts to develop best management practices, technical guidance, and model frameworks such as those undertaken by organizations like the API, EDF, and others have led to improvements in regulatory programs resulting in increased environmental protection. For

[7] Summary of Statewide Rule 8, https://www.rrc.state.tx.us/oil-and-gas/publications-and-notices/manuals/surface-waste-management-manual/swr8-summary/

example, the GWPC and the IOGCC facilitate multi-state collaboration and innovative regulatory solutions for oil and natural gas producing states." As member organizations of state governments, the GWPC and IOGCC are in the unique position to coordinate efforts between the federal government and states to ensure that advances in regulatory regimes are efficient and effective. GWPC and IOGCC have each (and in partnership) published several reports related to oil and gas exploration and production regulation including a 2021 updated version of a report on Potential Induced Seismicity.[8]

8 Potential Induced Seismicity: A Resource of Technical & Regulatory Considerations Associated with Fluid Injection, https://www.gwpc.org/wp-content/uploads/2022/12/FINAL_Induced_Seismicity_2021_Guide_33021.pdf

Chapter 4: Oil and Gas Regulations

As previously noted, this report includes a review of state oil and gas regulations in areas such as permitting, hydraulic fracturing, well integrity, plugging, and others. The following represents the findings for each of the areas and related elements listed in Appendix 4.

Permitting

Permitting is the process of authorizing the drilling and completion of a well for oil and gas purposes and other activities associated with oil and gas E&P. It includes a regulatory review of information concerning well locations, depths, proposed construction, applicant status, financial assurance, and many other things.

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 to drill a well for the extraction of oil or gas and provides the applicant's drilling plan. Second, the permit application provides the regulatory agency with information such as the location, proposed depth, target formations, and proposed construction of the well. In some agencies, well construction plans are reviewed and approved through other processes subsequent to issuance of a drilling permit; however, all agencies evaluate proposed construction plans before drilling commences. Based on this information, the regulatory agency can evaluate the proposed well to determine whether it meets the current regulatory requirements for drilling, construction, and operation. In some agencies, the permit covers not only the drilling of the well but other activities including well treatment, hydraulic fracturing stimulation, storm water management, the construction of the wellsite, excavation of pits, and authority to plug a drilled dry hole. For example, in Arkansas, the applicant is also required to submit a lease facility plan, including pit construction specifications. The Arkansas Oil Conservation Commission must approve lease facility plans before drilling can begin. The Oil and Gas Commission and the Division of Environmental Quality, both now part of the Arkansas Department of Energy and Environment, have joint enforcement of specific provisions of this rule requirement. Other states may authorize such activities through a series of permits.

Authority to require permits for the drilling of oil, gas, and service wells (injection wells and others) is usually delegated by the state legislature to an oil and gas division, commission, or board. Although sometime elected, heads of commissions or oil and gas agencies are typically appointed by either an agency head or by a governor and they are often geologists, engineers, or attorneys. Staffs usually include engineers, geologists, or environmental scientists with technical training and qualified to review applications for both conservation and water resource protection purposes.

Permits constitute a license issued by the state to conduct an activity. Regardless of the activity authorized by the permit, the permit holder must otherwise have a legal right to conduct the activity. With respect to oil and gas operations this right is usually specified in a lease, which details the rights and responsibilities of the mineral rights owner and the oil and gas operator.

All 27 oil and gas producing agencies in the study have permitting requirements governing the locating, drilling, completion, and operation of oil and gas related wells.

Scope of Permitting Review

This study reviewed state permitting requirements with respect to nine types of permits/ authorizations (Table 4-1)

Permit Type	Includes:
Drilling	Permits to drill new oil or gas related wells.
Deepening/ redrilling	Permits to deepen an existing well or drill out a plugged well.
Workover	Permits to conduct a workover on an existing well.
Wellpad construction	Permits to develop the wellsite including pad construction and equipment placemen.t.
Stormwater management	Permits to construct well-sites and surface facilities for the purpose of preventing stormwater runoff during drilling operations.
Hydraulic fracturing	Permits to hydraulically fracture a new or existing oil or gas well.
Temporary abandonment	Prior authorization to temporarily abandon or shut-in a well.
Pits (Drilling and produced water storage)	Prior authorizations to construct and operate various types of pits.
Storage tanks	Prior authorizations to construct and operate above ground oil and produced water storage tanks.

Table 4-1 Permit Types

NOTE: Plugging permits; which was a Permit Type listed in the 2014 report, were not included in the 2017 report or this report because the vast majority of agencies do not issue a separate permit for this activity. However, all 27 states require a prior notice of intent to plug and 21 require submission of a plugging plan to the agency.

January 2021 Findings

A review of state regulations relative to permitting indicates all 27 agencies require a permit for the drilling, re-drilling, or deepening of an oil or gas related well, while 22 also require a permit to workover an existing well. For the 2017 and 2021 editions of the report an additional category was included (Stormwater management). As of January 2021, six agencies require a permit for onsite-stormwater management. Eight agencies also require a permit for wellpad construction. In addition to wells and wellsites, agencies also issue permits and prior authorizations for other oil and gas activities. For example, 13 agencies issue permits or require authorizations for hydraulic fracturing and 22 require a separate authorization to temporarily abandon a well. With respect to pits 15 agencies require a permit or prior authorization to construct and operate a drilling pit while 19 have prior authorization requirements for fluid storage pits. These figures represent increases from the 2017 report in every category. Figure 4-1 shows the number of agencies with permitting requirements for specific well drilling and wellsite activities in 2021.

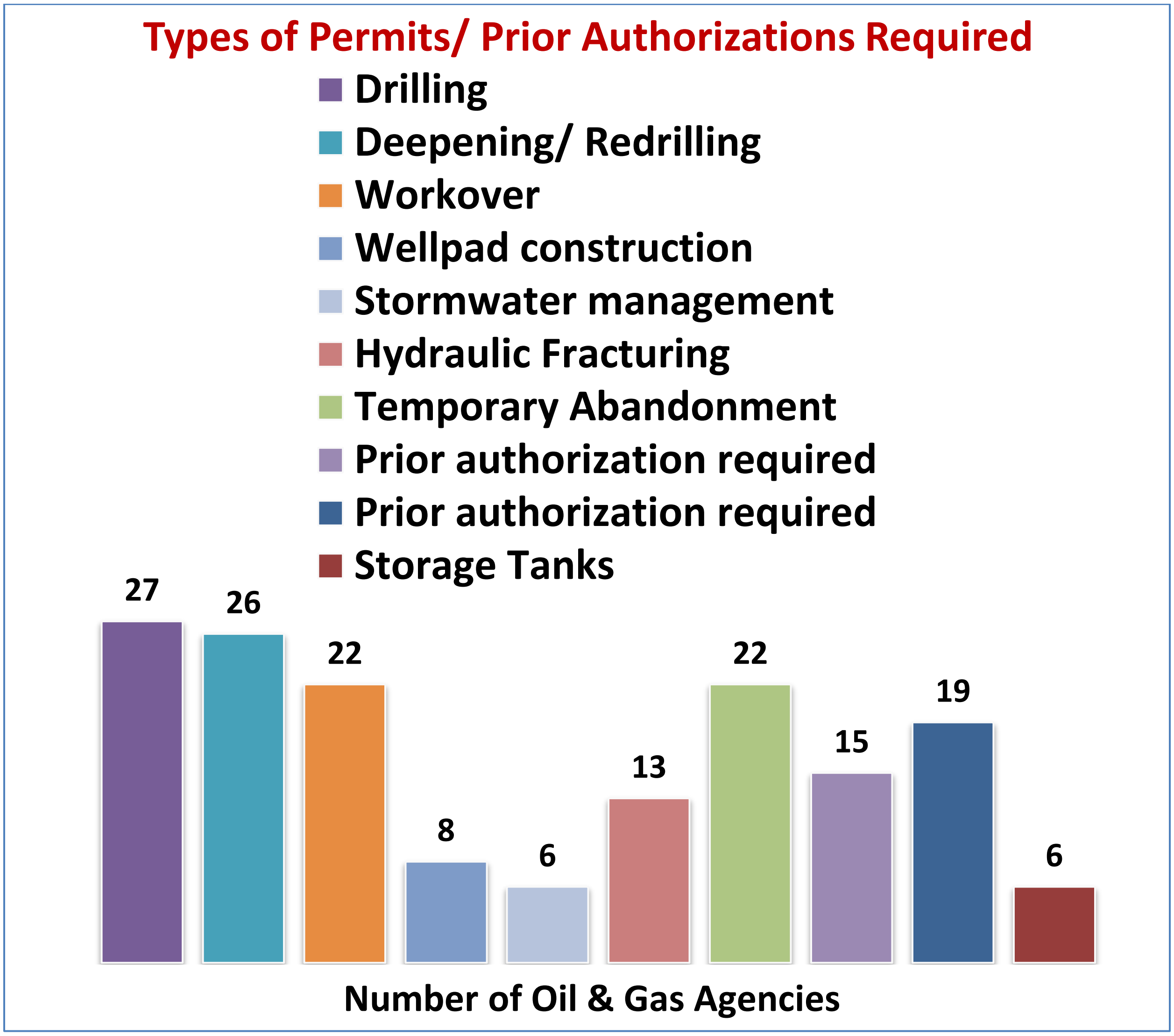


Figure 4-1

With respect to permit management, 22 agencies have regulations with provisions that allow the agency to delay or deny a drilling permit if the applicant is not in compliance with the regulations (a 10percent increase since 2017). Eighteen agencies may suspend, or revoke permits for non-compliance (Figure 4-2). It should be noted that regardless of regulatory language most, if not all, agencies have some authority to deny, delay or suspend a permit for cause.

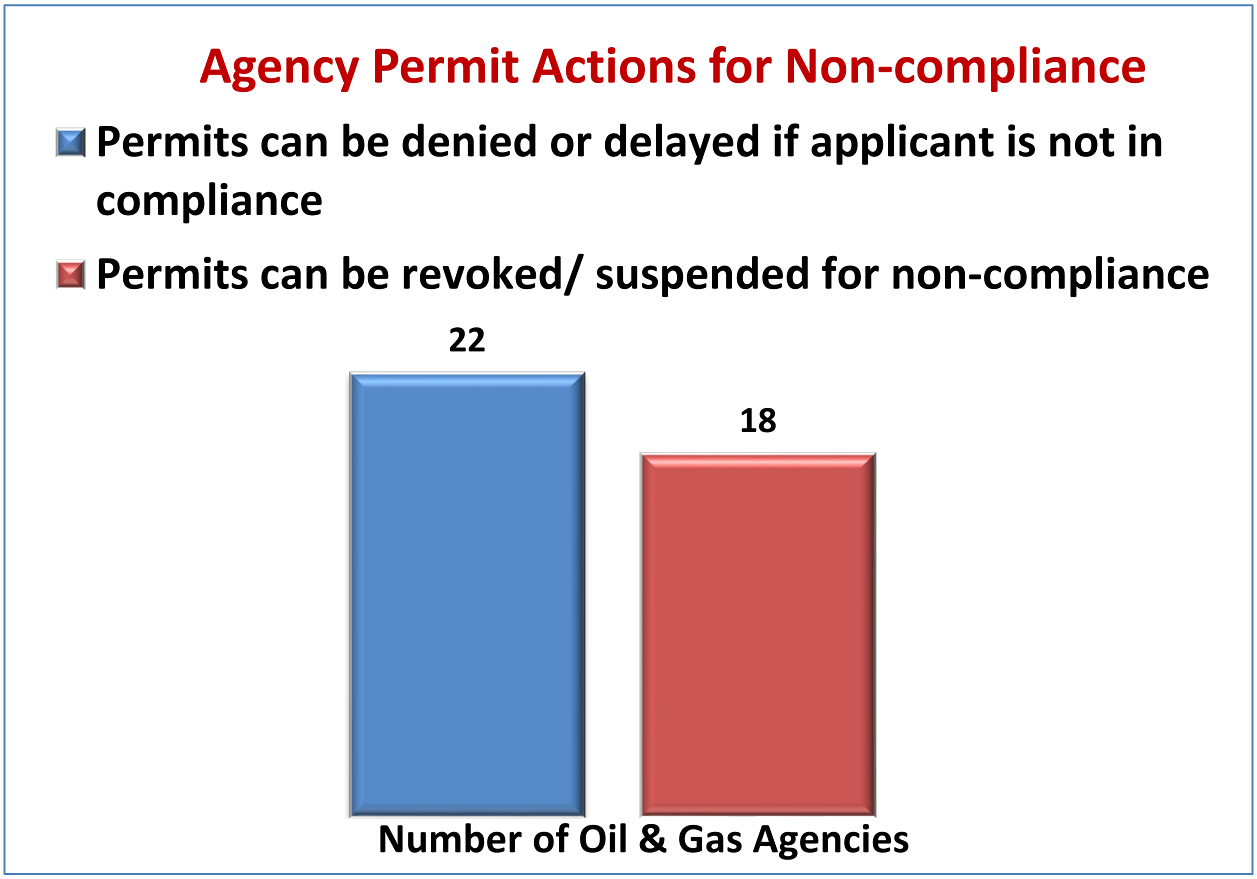


Figure 4-2

Hydraulic Fracturing

Well treatments fall into two primary categories:

- **Matrix treatments:** Matrix treatments are usually performed below reservoir fracture pressure and are designed to restore the natural permeability of the reservoir following damage to the rock that can occur as a consequence of the drilling, casing, and cementing process. Applying acid to the face of the formation below fracture pressure, or "acidizing," is a typical matrix treatment.

- **Hydraulic fracturing treatments:** Hydraulic fracturing is a process designed to create artificial fractures in the formation that increase the surface area of drainage and create greater conductive flow between the reservoir and the wellbore.

As in 2017, this report will focus on hydraulic fracturing treatments. Although matrix treatments are important in the development of oil and gas resources, their typically low pressure and less complex chemical makeup result in a lower hazard profile than hydraulic fracturing. Therefore, most agencies have focused their regulatory revisions primarily on hydraulic fracturing.

Matrix Treatments

Matrix treatments, such as acid jobs, are near-wellbore processes designed to remove near-well formation damage introduced during the drilling process by pumping acid through casing into the producing zone below pressures that would be necessary to create or propagate fractures. The process is designed to improve production by increasing the effective radius of the well. In some cases, typically in carbonate formations such as limestone, an acid fracturing process is performed above the fracture pressure of the formation. The process etches the surface of fractures and allows for a higher conductivity pathway from the reservoir to the wellbore. The mixture typically used for this process is a 15 percent to18 percent solution of acids that include hydrochloric acid sometimes mixed with acetic, formic, fluoroboric, and other acids. Because matrix treatments do not typically involve high pressures or volumes of additives and are thus considered lower risk, this study did not evaluate state rules governing these types of processes.

Hydraulic Fracturing Treatments

Hydraulic Fracturing Job Circa 1950

Figure 4-3 Source, FracFocus

Hydraulic fracturing is 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 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, resulting in increased production ratios vs. non-fractured wells. Between 2000 and 2015 this change in ratio resulted in a significant increase in the amount of oil and gas production where hydraulic fracturing is used. For example, the U.S. Energy Information Administration reported that in 2000 6.14 trillion cubic feet (tcf) of natural gas came from tight shale formations. By 2020 the natural gas production from tight shale formations had risen to 29.6 tcf.[9]. While this change can be attributed to many factors, two primary factors are the advances in horizontal drilling technology and the widespread use of high volume hydraulic fracturing.

The first commercial application of hydraulic fracturing as a well treatment technology designed to stimulate the production of oil or gas occurred in either the Hugoton field of Kansas in 1946 or near Duncan, Oklahoma, in 1949. In the ensuing 60 plus years, hydraulic fracturing has become a routine technology that is frequently used in the completion of gas wells, especially those drilled into unconventional reservoirs such as tight shale. In a paper written for the Society of Petroleum Engineers it was estimated that, since 1949, more than 2.5 million fracture jobs have been conducted on oil and gas wells worldwide.[10] According to the U.S. Energy Information Administration (EIA), 69 percent of all new oil and natural gas wells drilled in the U.S. are hydraulically fractured and horizontally drilled.[11]

The only viable alternative to fracturing producing formations in reservoirs with low permeability would be to drill more wells in an area. Given the costs of drilling, the risks associated with creating multiple new vertical pathways for fluid migration, and the fact that it could take exceptionally large numbers of vertical wells located over a large area to equal the production of even a single hydraulically fractured horizontal well, this alternative is likely neither environmentally desirable nor economically viable. To overcome this, operators commonly drill multiple horizontal wells in different directions from a single wellpad site and these wells may extend laterally for several miles from the vertical aspect of the wellbore. From an environmental perspective, the API concludes that "horizontal drilling allows producers to drill multiple wells from a single well pad site, reducing surface disturbance and minimizing impacts on species and landscapes."[12]

A great deal of attention has been focused on the process of hydraulic fracturing. Media outlets, environmental groups, citizen organizations, and the oil and gas industry have each expressed opinions about the safety and environmental effects of hydraulic fracturing. Addressing the issue is complicated by differences among these groups in their understanding of what the process entails, and whether development of oil and natural gas is viewed as good energy policy. To the oil and gas industry, "hydraulic fracturing" generally is understood to mean the actual process of

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[9] Where Our Natural Gas Come From, U.S. Energy Information Administration, https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php

[10] George E. King, Apache Corp., Hydraulic Fracturing 101: What Every Representative, Environmentalist, Regulator, Reporter, investor, University Researcher, Neighbor and Engineer Should Know About Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and Oil Wells, SPE Paper 152596 (Feb. 2012).

[11] Energy Information Administration (EIA), https://www.eia.gov/todayinenergy/detail.php?id=34732

[12] American Petroleum Institute (API), https://www.api.org/~/media/Files/Oil-and-Natural-Gas/Hydraulic-Fracturing/Environmental-Stewardship/Hydraulic-Fracturing-and-Horizontal-Drilling-Provide-Environmental-Benefits.pdf

pumping fluids and proppant under pressure to fracture the rock. To others, hydraulic fracturing has become a more inclusive term that encompasses every activity associated with natural gas development from pad construction, drilling, production, pipeline transportation of gas, midstream processing of the product, and the disposal of waste products. Differences in the definition of hydraulic fracturing have led to misunderstandings and resulted in a greater level of concern than may have otherwise been associated with the discrete process of fracturing the formation. Regardless, it is important to note public discourse has continued to shift from an almost singular focus on hydraulic fracturing to other E&P issues such as well integrity failure, methane leaks, air pollution, plugging of abandoned wells and urban drilling.

Fracturing Fluids

Fracturing fluid formulations may be based on water, acid, gel, or other media such as carbon dioxide or nitrogen foam. However, most fracturing work is conducted using water-based fluid. In addition to water, fracturing fluids typically contain an 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.[13] This type of fracturing process is often referred to as a "slickwater" fracture. The majority of additives to fracturing fluids, including sodium chloride, potassium chloride, and diluted acids, present low to very low risks to human health and the environment (Figure 4-4)[14]. However, some substances used in some hydraulic fracturing operations, such as ethylene glycol, components of petroleum distillates, and additives that contain or can be transformed into other, more harmful substances, have been linked to negative health effects at certain exposure levels.

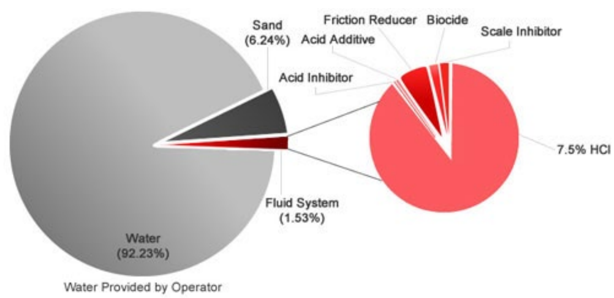

Figure 4-4 Typical ratio of fluids, by type, in a slickwater hydraulic fracturing fluid - Source, ALL Consulting

To address questions regarding the availability of information about the ingredients used in the hydraulic fracturing process, the GWPC and IOGCC worked together in early 2011 to create a

[13] P. Kaufman, G.S. Penny, J. Paktinat, Critical Evaluation of Additives Used in Shale Slickwater Fractures, SPE 119900 (Nov. 2008).

[14] Robert Porges & Mathew Hammer, National Ground Water Association, The Compendium of Hydrogeology (2001).

national hydraulic fracturing chemical registry. This system, (FracFocus®)[15] provides a platform for operators to submit information about the constituents used in the hydraulic fracturing process. It offers critical information to the public about the ingredients in hydraulic fracturing jobs and has become the de-facto standard for hydraulic fracturing chemical reporting in the U.S. with 23 states currently using it to meet their regulatory reporting needs.

Although a 2008 study conducted on behalf of the GWPC, with funding provided by the Department of Energy (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 and proppants by volume, the increasing volumes being used to fracture wells still result in substantial overall volumes of additives. For example, in a hydraulic fracturing job that uses a base fluid volume of 10 million gallons of water a chemical that makes up only 0.01 percent of the total mixture would have a volume of 1,000 gallons.[16] Fortunately, the dilution factor, presence of formation fluids, typical distances between fractured zones and groundwater zones, and the fact that chemicals such as acids are typically neutralized during the process, results in a very low probability that chemicals would contaminate groundwater resources. *NOTE: The 2008 primer is currently being updated with an expected release by mid-2023.*

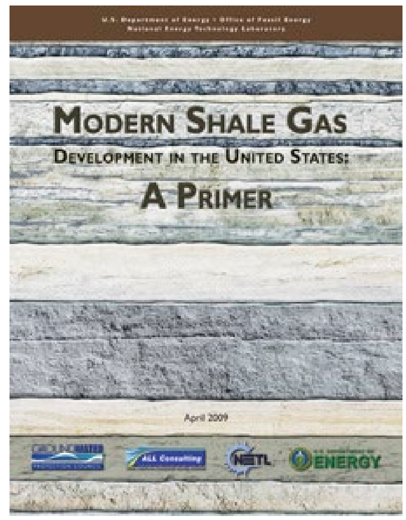

Figure 4-5 Shale Gas Primer- Source, GWPC

One conceivable way to reduce public concerns about the additives used in hydraulic fracturing would be to exclusively use additives that are not associated with human health effects nor adversely impact the natural environment. For example, the oil and gas industry has responded to public and regulatory calls for the use of "greener" chemicals in hydraulic fracturing operations by developing alternatives to some ingredients, including diesel fuel. Research and development of alternative ingredients continues to advance and should result in an increased use of more environmentally friendly constituents over time. With respect to diesel fuel, which was cited as a principal constituent of concern by the U.S. Environmental Protection Agency (EPA) and the Oil and Gas Accountability Project (OGAP) because of its relatively high benzene content, a Memorandum of Agreement between the EPA and industry was reached in 2003 to discontinue diesel fuel use as a fracture fluid media in coalbed zones that qualify as Underground Sources of

15 http://www.fracfocus.org
16 Groundwater Protection Council & ALL Consulting, Modern Shale Gas Development in the United States: A Primer (Apr. 2009) (prepared for DOE and the National Energy Technology Laboratory).

Drinking Water (USDWs) (Appendix 10). In 2008, the GWPC conducted a follow-up survey, which found that in 25 agencies with potential coalbed methane production, diesel fuel was not being used to hydraulically fracture coalbeds that are USDWs. Between the development of the initial MOA in 2003 and the 2008 follow-up survey, Congress passed the Energy Policy Act in 2005. The act stated that hydraulic fracturing would not be considered a UIC activity unless diesel fuel was used. In February of 2014, EPA issued a final guidance document (Guidance #84) describing the criteria under which hydraulic fracturing would be considered a UIC activity requiring a permit[17]. In practice, diesel fuel use has dramatically decreased for well stimulations of all types, including hydraulic fracturing of shale formations. To evaluate the extent of diesel fuel use in hydraulic fracturing a recent review of FracFocus records of over 62,000 disclosures submitted between June 2016, and January 1, 2021, shows that in only fifteen stimulations (0.02 percent of fracture jobs) were any of the additives listed in EPA guidance #84 used. This contrasts with just over 105,000 records containing 54 such occurrences (0.05 percent of fracture jobs) found in a review of the FracFocus system between January 1, 2013, and May 1, 2016, and a nearly 0.04 percent use in fracture jobs between January 1, 2015, and May 31, 2016. Based on a comparison of these occurrence rates, the use of diesel fuel use in hydraulic fracturing has steadily decreased between 2014 and 2021.

Exposure Pathways

The exposure effects of additives that can be contained in the treatment fluids can be mitigated by reducing exposure pathways. This is accomplished by ensuring the well being treated maintains mechanical integrity and by utilizing natural hydraulic barriers between the fractured zone and protected groundwater. Relevant to an analysis of exposure pathways in a GWPC/DOE study, discussed previously, which found that, depending on the design of a fracture job and the specific formation dynamics involved, anywhere from 30 percent to 70 percent of fracturing fluids are returned to the surface through the well casing.[18] 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 groundwater.[19] The risk of endangerment to groundwater is further reduced by other factors such as:

- Well construction practices including state regulatory standards and industry guidelines;
- Vertical distance between the fractured zone and groundwater;

[17] Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuel, Underground Injection Control Program Guidance #84, Office of Water (4605M) EPA 816-R-14-001, February 2014
[18] Groundwater Protection Council & ALL Consulting, Modern Shale Gas Development in the United States: A Primer (Apr. 2009) (prepared for DOE and the National Energy Technology Laboratory).
[19] USEPA, Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs, EPA 816-R-04-003 (June 2004).

- Presence of other zones between the fractured zone and the deepest groundwater zone that may readily accept fluid;
- Natural stress-induced limitations on vertical fracture propagation;
- Natural limits to fracture propagation posed by friction and fluid leakoff in the stimulated zone during the hydraulic fracturing operation;
- Presence of low permeability confining zones between the fractured zone and the deepest groundwater zone, which act as geologic barriers to fluid migration;
- Operational controls, such as the continuous monitoring of wellbore integrity during hydraulic fracturing operations; and
- Emerging sensor technologies which may allow for rapid detection of subsurface leaks.

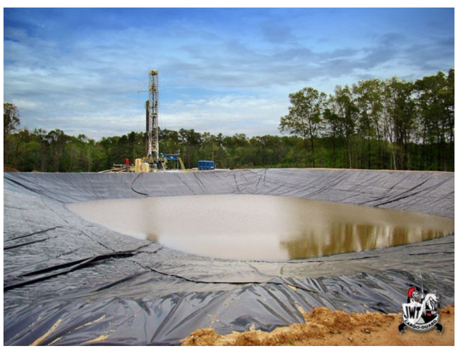

Figure 4-6 Lined pit designed to hold fluids during well drilling and completion - Source, IWT/ Cargo-Guard

While the widespread use of effective, lower toxicity alternatives to traditional additives would decrease risk of environmental harm, the best way to protect groundwater is to isolate well treatment fluids from groundwater 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 groundwater.

Additionally, proper surface fluid handling methods can significantly decrease the likelihood of environmental harm from, or human exposure to, well treatment fluids. For example, once flowback fluids return to the surface, they are temporarily stored in tanks or lined pits (Figure 4-6) to isolate them from soils and shallow groundwater zones and are subsequently removed from the location for recycling or disposal. Exposure risk is, therefore, limited to spills and leaks from storage and transportation, which can be minimized by smart management practices and effective rules.

The ultimate fate of well treatment fluids returned to the surface is often determined by the availability of treatment and disposal technologies such as on-site or centralized treatment facilities and injection wells. Underground disposal via injection wells under the jurisdiction of a UIC program is the most common method of disposal for used fracture fluid. Prior to disposal, fluids are sometimes treated and re-used in subsequent fracturing operations, a practice that has seen increased attention and use in recent years. This growing trend toward recycling and reuse of fluids is discussed in "*Key Message 2: Emerging Issues*". For facilities west of the 98th meridian, on-site treatment, and surface discharge, though rarely used, is also a disposal option, where authorized by EPA or a state regulatory agency[20] (Figure 4-7). East of the 98th meridian, on-site treatment and direct surface discharge is typically not allowed.

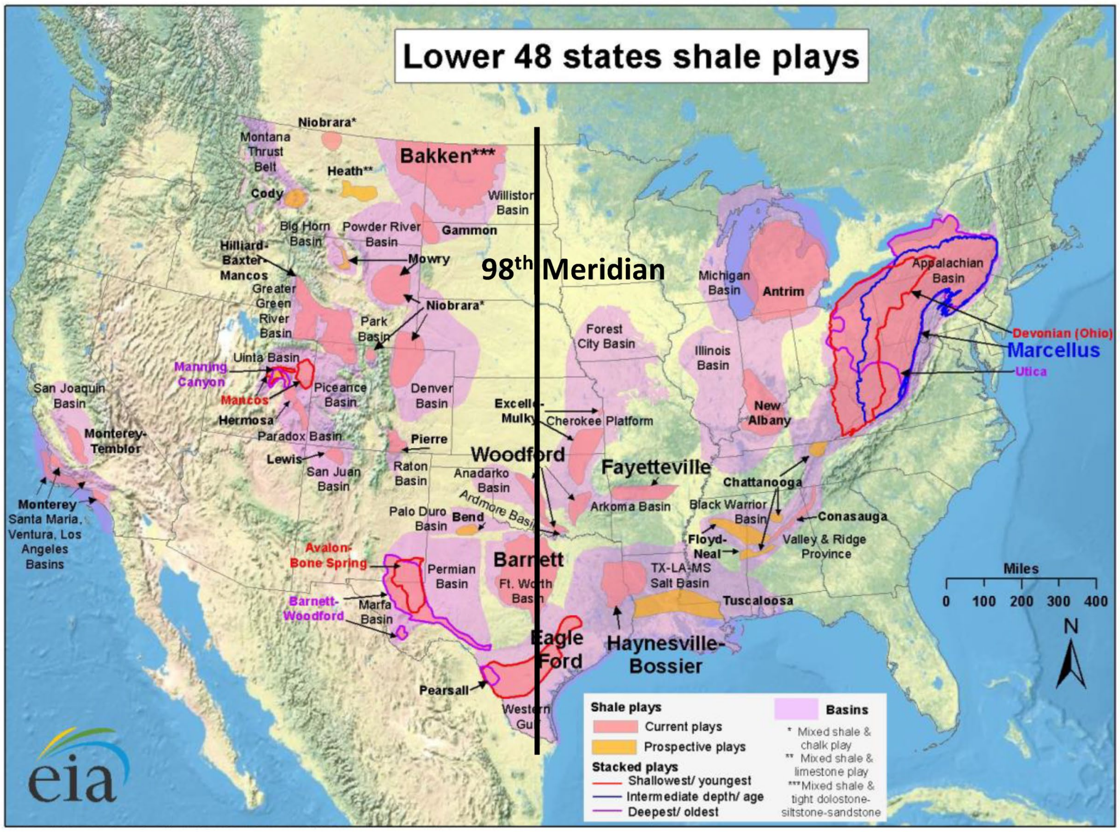

Figure 4-7 Shale plays in the lower 48 states – Source, Energy Information Administration

As noted in the 2014 edition of this report, indirect discharges such as through publicly owned treatment works (POTWs) or centralized wastewater treatment facilities (CWTs), was sometimes conducted, provided the fluid would not cause the facility to violate its permit or any state or national water laws or guidelines.[21] In June 2016, EPA published a new rule governing effluent limitations and standards for the onshore oil and gas industry. A clarification to these effluent limitations was published in the Federal Register in 2019.[22]This rule established pretreatment standards that prevented the discharge of pollutants in wastewater from onshore unconventional oil and gas (UOG) extraction facilities to POTWs because certain UOG extraction wastewater constituents are not typical of POTW influent wastewater and can be discharged, untreated, from the POTW to the receiving stream.

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[20] Oil and Gas Extraction Point Source Category, 40 C.F.R. pt. 435 (subpart E—Agriculture and Wildlife Use Subcategory).

[21] *See generally,* James Hanlon, Director, Office of Wastewater Management, EPA, Natural Gas Drilling in the Marcellus Shale: NPDES Program Frequently Asked Questions (Mar. 2011).

[22] Federal Register Notice 84 FR 32094, July 2019, https://www.federalregister.gov/documents/2019/07/05/2019-14361/decision-on-supplemental-information-on-the-effluent-limitations-guidelines-and-standards-for-the

Isolation Techniques

The risk of groundwater contamination resulting from the flowback of well treatment fluids returned to the surface through casing is low, since it would require simultaneous failures of multiple barriers of protection such as casing strings and cement sheaths.[23] A greater risk of contamination of groundwater comes from the potential for well treatment fluids to migrate upward within the casing/formation annulus during the treatment process and from surface spills; which may more readily affect shallow, unconfined groundwater zones. The most effective means of protecting groundwater from upward migration in the annulus is the proper cementation of well casing across vertically impermeable zones and groundwater zones. Proper cementation creates the hydraulic barriers that prevent fluid incursion into groundwater. The amount and placement of cement needed for this purpose will vary depending on 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 groundwater; and
- Distance between the fractured zone and groundwater.

In general, the vertical separation between an oil and gas producing formation and the deepest groundwater zone in many parts of the country can be several thousand feet. However, there are cases where the distance between the producing zone and the groundwater zone is much smaller. In such cases, special considerations for constructing wells and conducting well stimulations may apply. For example, Texas has specific additional regulations governing wells that do not meet a "minimum vertical distance" between the zone to be fractured and protected groundwater zones.[24] Although a GWPC 2008 survey of state regulatory agencies found no determinations of contamination from the relatively shallow hydraulic fracturing of CBM reservoirs, the Texas rule indicates that concerns continue to exist. Regardless, the lack of demonstrated groundwater contamination where substantial intervals between the fractured zone and protected groundwater exist make it reasonable to conclude the risk of fracture fluid intrusion into groundwater from the hydraulic fracturing of deeper conventional and unconventional oil and gas zones should be considered very low.

[23] Groundwater Protection Council & ALL Consulting, Modern Shale Gas Development in the United States: A Primer (Apr. 2009) (prepared for DOE and the National Energy Technology Laboratory).
[24] Texas Administrative Code, Title 16 Economic Regulation, Part 1 Railroad Commission of Texas, Chapter 3 Oil and Gas Division, April 2013

This conclusion is supported by the following factors:

- There is often significant vertical separation between the fractured zone and groundwater zones, especially in the majority of deep shale gas plays;[25]
- Well construction requirements in most agencies include provisions for cementation above producing zones and across groundwater zones;
- There are frequently layers of rock between the fractured zone and groundwater zones that are capable of accepting fluid under pressure, which would lower the available fluid that could reach a groundwater zone;
- There are also frequently layers of rock between the fractured zone and groundwater zone through which vertical flow is restricted, thus serving as a hydraulic barrier to fluid migration; and
- 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.

Regulation of Formation Stimulation

The authority to regulate the treatment of oil and gas wells is typically part of the general provisions of state oil and gas law; which contains a prohibition against pollution or contamination by oil and gas activities. Until recently, most well treatment practices were not regulated directly. Instead, oil and gas agencies regulated practices such as well construction and well testing, which are designed to prevent the migration of all fluids, including hydraulic fracturing fluids, from deeper to shallower zones. Provided these requirements are followed properly, and provided there are good geologic barriers between groundwater and the fracture zone that are not compromised by unplugged or poorly plugged abandoned wells, the process of formation stimulation itself should not affect groundwater. Some agencies, such as Oklahoma, have consolidated existing regulations with a relationship to well treatment into a single section of their regulatory language. Other agencies have introduced new direct regulation on acceptable chemical use, pre-stimulation reporting requirements, pressure limitations and monitoring standards, cessation of operations for MI failure, and surface equipment integrity testing.

Limitations and Requirements

As of January 2021, more agencies had placed specific limitations on the well treatment process. The following is a partial list of well treatment requirements by rule and examples of some states that implement them:

[25] Groundwater Protection Council & ALL Consulting, Modern Shale Gas Development in the United States: A Primer, (Apr. 2009) (prepared for DOE and the National Energy Technology Laboratory).

- Prohibitions against, or prior approval for, the use of some chemicals (Alabama, Arkansas, Colorado, Illinois, Oklahoma, Utah, and Wyoming);
- Minimum depths or distance from protected water (Alabama- Coalbed methane only, Texas);
- Geologic evaluations of the interval between the zone to be fractured and groundwater zones (Alabama, Alaska, Arkansas, California, Illinois, Indiana, Mississippi, and Texas);
- Additional requirements on wells that do not meet a minimum intervening interval between the fractured zone and protected groundwater (Texas);
- A review of the area around the wellbore for natural and artificial conduits (Alabama, Alaska, Arkansas, California, Illinois, Indiana- Coalbed methane only, Mississippi, Ohio, and West Virginia);
- Adjacent water well testing and monitoring (Alaska, Arkansas, California, Colorado, Illinois, Indiana, Kentucky, Michigan, Ohio, Virginia, West Virginia, and Wyoming);
- Requirements that fracture fluids be confined to the zone to be fractured (Alabama, Alaska, Arkansas, California, Colorado, Illinois, Indiana, and Mississippi);
- Annular pressure monitoring during fracturing operations with job termination criteria (Alaska, Arkansas, California, Illinois, Indiana, Michigan, Ohio, and Texas); and
- Pressure limitations (Alabama, Alaska, Arkansas, California, Illinois, Mississippi, Montana, Nebraska, and North Dakota).

NOTE: These examples do not comprise the full list of requirements or states.

Disclosure and Reporting

In the 2014 edition of this report, 21 of the agencies reviewed required some degree of reporting of chemicals used in wells. By the 2017 edition, the number of agencies requiring reporting had risen to 24. By 2021 this number had again risen, and is now 25. (An increase of 16 percent since 2014) Between 2009 and 2014 many agencies expanded their reporting requirements to include a list of the chemicals used in hydraulic fracturing jobs, the name of the supplier, the amount, or percent by mass of the chemicals used, the trade name of the products used, and the Chemical Abstract Number (CAS)[26] of each chemical used. In 2011, the GWPC and the IOGCC partnered to create a hydraulic fracturing chemical disclosure registry. This registry, known as FracFocus, was initially designed to be a website where oil and gas operators could report their hydraulic fracturing chemicals on a voluntary basis. The purpose of the site was to provide information about the process of hydraulic fracturing to the public and to allow nearby landowners to see records that showed the chemicals being used on or near their property. Prior to 2021 the FracFocus website allowed the public to search for hydraulic fracturing disclosure records using

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[26] The Chemical Abstract Service is maintained by the American Chemistry Council. *See generally*, Chemical Abstract Service , https://www.cas.org.

only such criteria as the state, county, operator, well name, date of job or submission date, and chemical names. In 2022 the public portion of FracFocus should be updated with a new user interface which will allow individuals to also use counties and zip codes to search for nearby hydraulic fracturing disclosure records, and to display their locations on a map. FracFocus presents individual disclosure records in an Adobe pdf ® format which can be printed or downloaded. In May 2015 the FracFocus system also began providing downloads of machine readable datasets in SQL and CSV formats. These downloads are currently updated daily and posted to the FracFocus website along with instructions for obtaining them. As of July 25, 2022, more than 2,100 companies had signed up to submit records to the system and more than 1,700 companies have submitted almost 196,000 disclosures.

As the popularity and effectiveness of the FracFocus website grew, several agencies decided to adopt the site as their means of regulatory reporting. As of the 2017 report 20 of the 27 agencies reviewed had designated the FracFocus website as an official location for filing regulatory chemical disclosures. By 2021 this number had risen to 23 of the 27 agencies reviewed. 2014 (See Appendix 12**-** current as of January 2021). Three agencies that were not part of this review (North Carolina, Nevada, and Idaho) also require or allow the use of FracFocus.

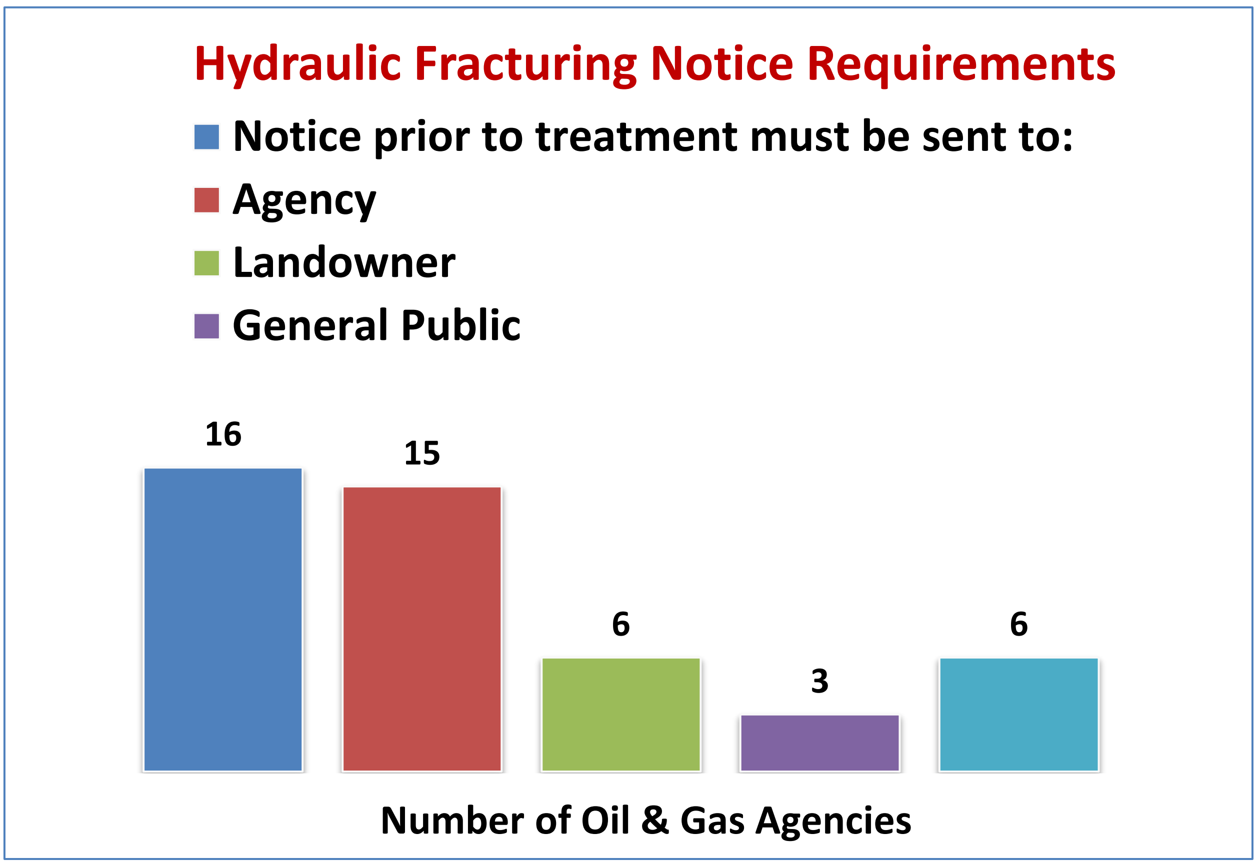

Figure 4-8

January 2021 Findings

Regulatory requirements on hydraulic fracturing have been increasing as a result of both public concern and evaluations of need by oil and gas agencies. A review of regulations relative to hydraulic fracturing shows that 23 of the reviewed agencies have specific regulations governing the practice. Further, 16 agencies require a prior notice to the agency before fracturing can be initiated. Additionally, 12 agencies require adjacent water well testing as a condition of conducting hydraulic fracturing. Figure 4-9 details some hydraulic fracturing requirements and the number of agencies that implement them.

In addition to the permitting requirements for hydraulic fracturing, there are 16 agencies that require a prior notice to the agency or to other persons when hydraulic fracturing is to be conducted. For example, while 15 agencies required a prior notice to the agency, there were also six that required notification being given to landowners and another six that required prior notice to offset operators. Figure 4-9 shows the prior notice requirements for hydraulic fracturing.

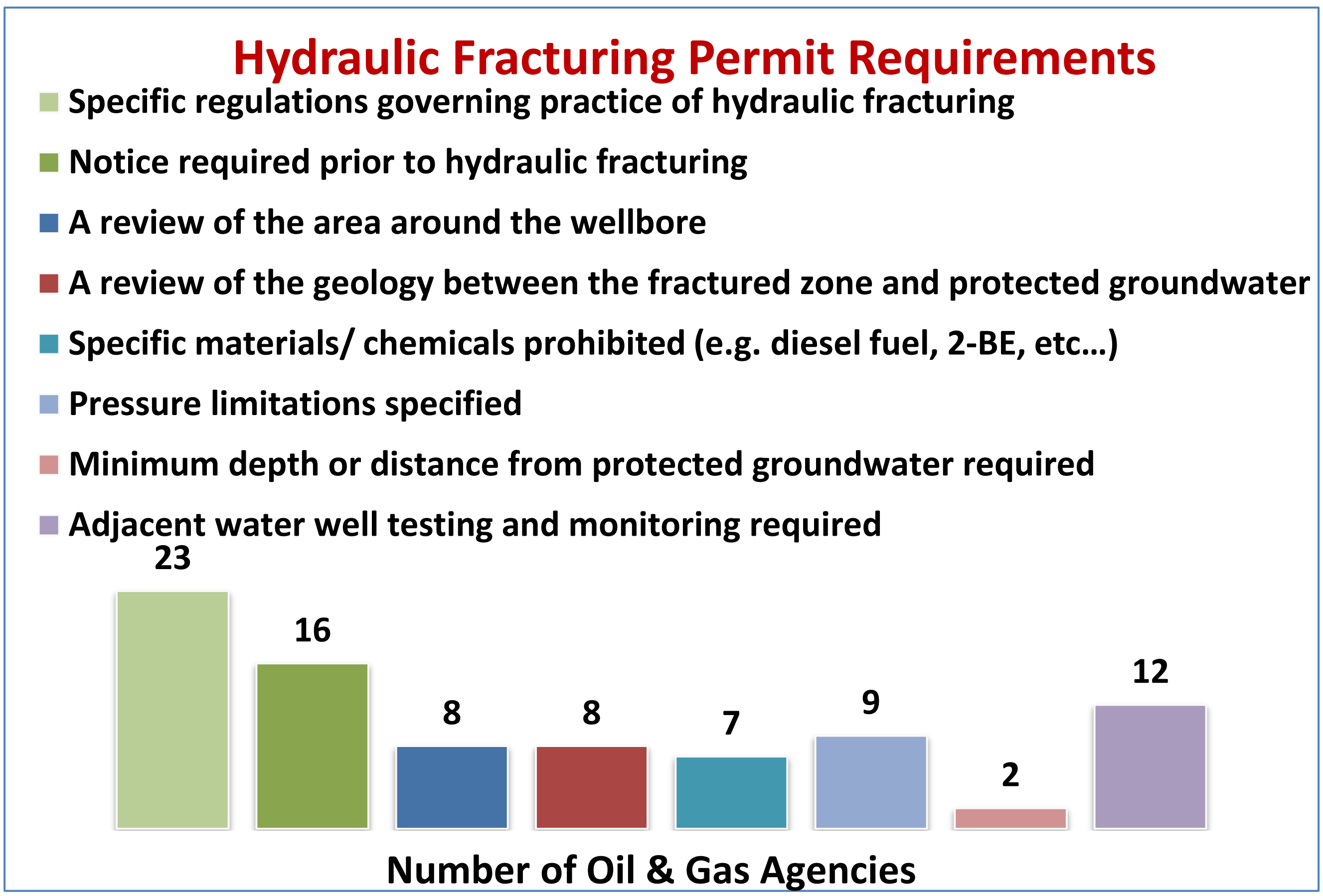

Figure 4-9

With respect to the operational requirements imposed by agencies on the process of hydraulic fracturing several are notable. Eight agencies specifically require the hydraulic fracturing fluid to be confined to the target reservoir. In 11 states the agency requires operators to monitor and record the fracturing job. If mechanical integrity failure is indicated during the job, ten agencies require immediate cessation of fracturing (a 30 percent increase since 2017). Figure 4-10 shows some of the specific operational requirements and the number of agencies that apply them.

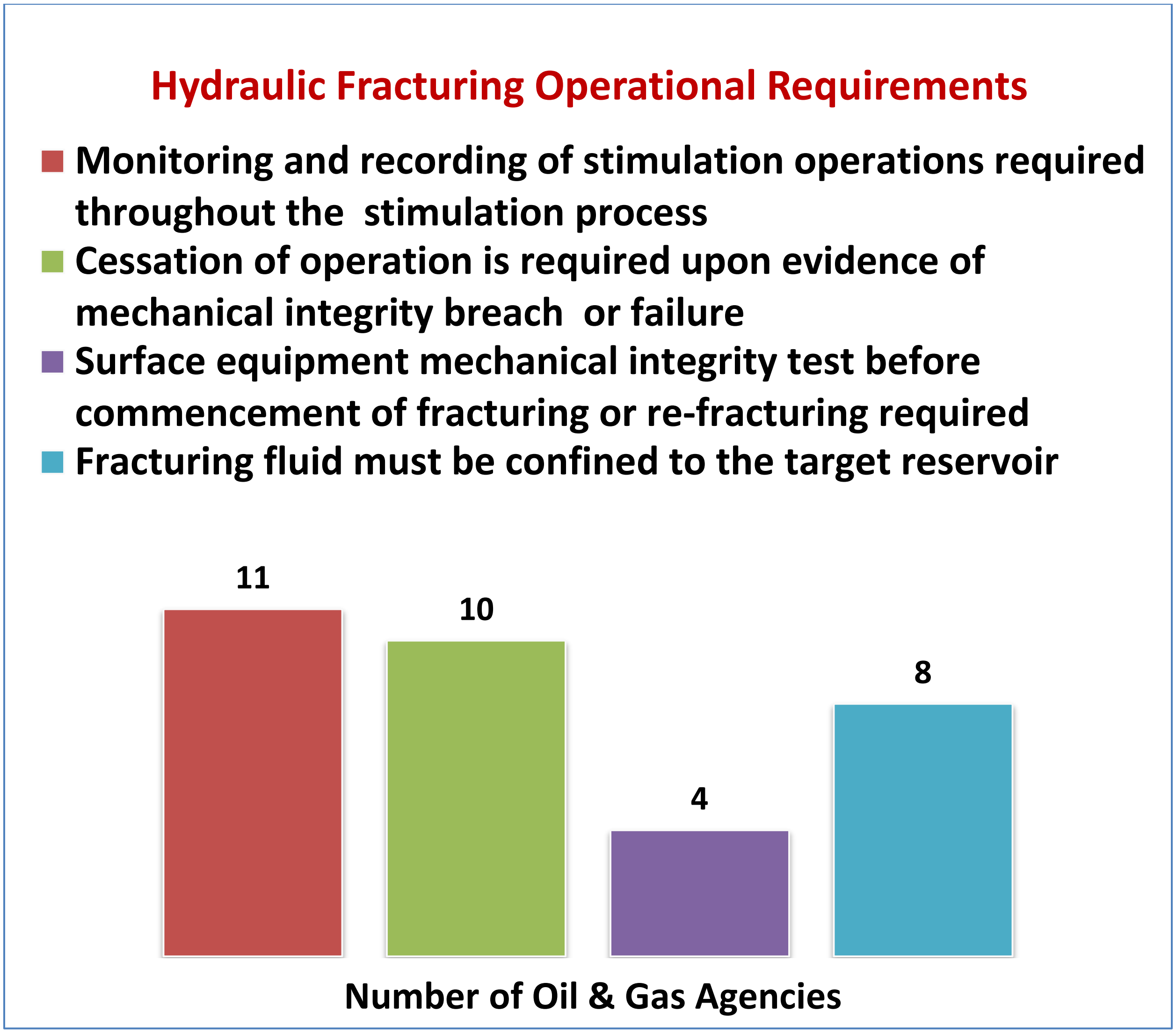

Figure 4-10

Although all of the states reviewed required some information such as types and amounts of materials used to be reported to the agency following hydraulic fracturing operations, 26 agencies specifically require post hydraulic fracturing chemical disclosure reporting.

Twenty-six agencies require submission of water volumes used and the specific additives and the volumes of each, or their percentages against the total volume used in the job (an almost 12 percent increase since 2017). Figure 4-11 details some of the post hydraulic fracturing reporting requirements.

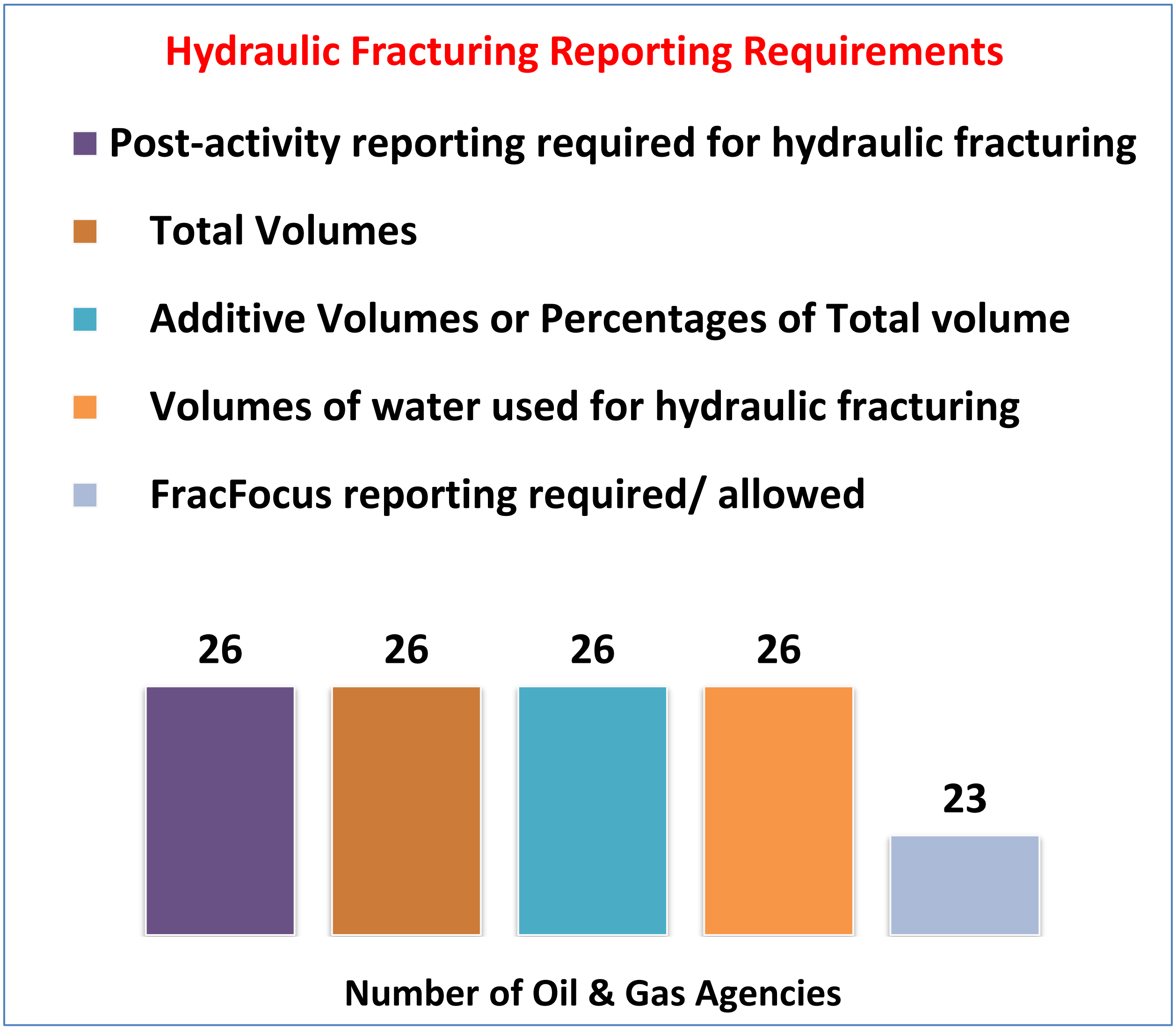

Figure 4-11

Appendix 3 is an example of a typical chemical disclosure report from the FracFocus system shown in the "Systems Approach" format which decouples the trade name of the product from its ingredients.

Well Integrity

From the perspective of water protection, well integrity means the structurally sound construction of a well including competent pressure seals and operational controls that effectively prevent uncontrolled fluid releases or migration of annular fluids into protected groundwater throughout the life cycle of a well. In August 2016, the GWPC developed a list of well integrity regulatory elements in six categories which agencies may want to consider when addressing well integrity. These elements were updated in 2021.[27]

In the 2013 Society of Petroleum Engineers (SPE) Paper # 166142, "*Environmental Risk Arising from Well Construction Failure: Difference Between Barrier and Well Failure, and Estimates of Failure Frequency Across Common Well Types, Locations and Well Age*," petroleum engineers George King and Daniel King describe the difference between barrier failure and well integrity failure.[28] In a barrier failure case, a single barrier, or even multiple barriers in a well (casing and/or cement) may fail. However, provided additional layers of protection remain intact and flow pathways between the wellbore and the formation do not occur, a well can still be considered to have integrity. The key to maintaining integrity is establishing redundant barriers. As the authors put it, "In most well configurations, uncemented sections of inner pipe strings are designed to collapse under any over pressuring external load in the annulus before the pipe that forms the outer wall of the annulus can burst. This type of reactive barrier protects the integrity of the outer string with a sacrificial collapse of the inner string." In essence, the production string is designed to collapse under over pressure before the surface casing can be compromised.

Proper placement and cementing of surface casing is one of the most critical groundwater protection measures during well construction. Once in place, it is also critical to protect the surface casing shoe from annular fluids that are sufficiently pressurized to allow fluid migration into protected groundwater. Additional layers of casing and cement are emplaced to isolate producing zones and other flow zones that are encountered while drilling below the surface casing. The cementing of surface casing protects groundwater during the drilling process and isolates it from deeper saline and petroleum containing zones, which can also be over-pressured or contain corrosive fluids and present a threat to protected groundwater.

[27] Ground Water Protection Council, Well Integrity Regulatory Elements for Consideration, https://www.gwpc.org/wp-content/uploads/2021/03/Well_Integrity_Elements_Revised_1_19_2021_002.pdf

[28] George E. King and Daniel E. King, Environmental Risk Arising from Well Construction Failure: Difference Between Barrier and Well Failure, and Estimates of Failure Frequency Across Common Well Types, Locations and Well Age, SPE 166142 (2013).

Well Materials and Construction Requirements

Casing is typically steel pipe used to line the inside of the drilled hole (wellbore). The most widely used standard for oil and gas casing was established by the API in Spec. 5CT. It specifies 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 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. API SPEC 10A, 25th Edition, March 2019 established standards for cement types, listing 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.

The Casing and Cementing Process

In general, the casing of oil and gas wells, whether vertical or 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 soil layers. After the conductor casing is set, drilling continues inside the conductor string to below the lowest protected groundwater zone depending on regulatory requirements. Surface casing is then run from the surface to just above the bottom of the hole. As of 2021, 26 of the 27 states reviewed specifically require the setting of surface casing below all protected groundwater zones. In one state this is not a specific requirement. Instead, this state uses a casing setting depth table, which is designed to accomplish a similar result. After surface casing is run, 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 of 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 ensures that the entire annular space fills with cement from below the deepest groundwater zone to the surface. All 27 of the agencies reviewed in 2021 required the circulation of cement around the surface casing.

Once the surface casing is set and the cement has time to cure, the wellbore is drilled down to the next zone where the intermediate or production casing will be set. In some agencies, an intermediate casing string is often run after the surface casing but before the production casing. This is usually required only 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 or to protect natural resources. In Ohio, where surface casing is typically set between 300 and 700 feet due to the shallow nature of protected groundwater, construction rules for new wells mandate installation of intermediate casing string in all horizontal wells as an additional pressure control barrier. Since hydro-geologic and reservoir characteristics differ regionally, intermediate casing requirements vary from state to state.

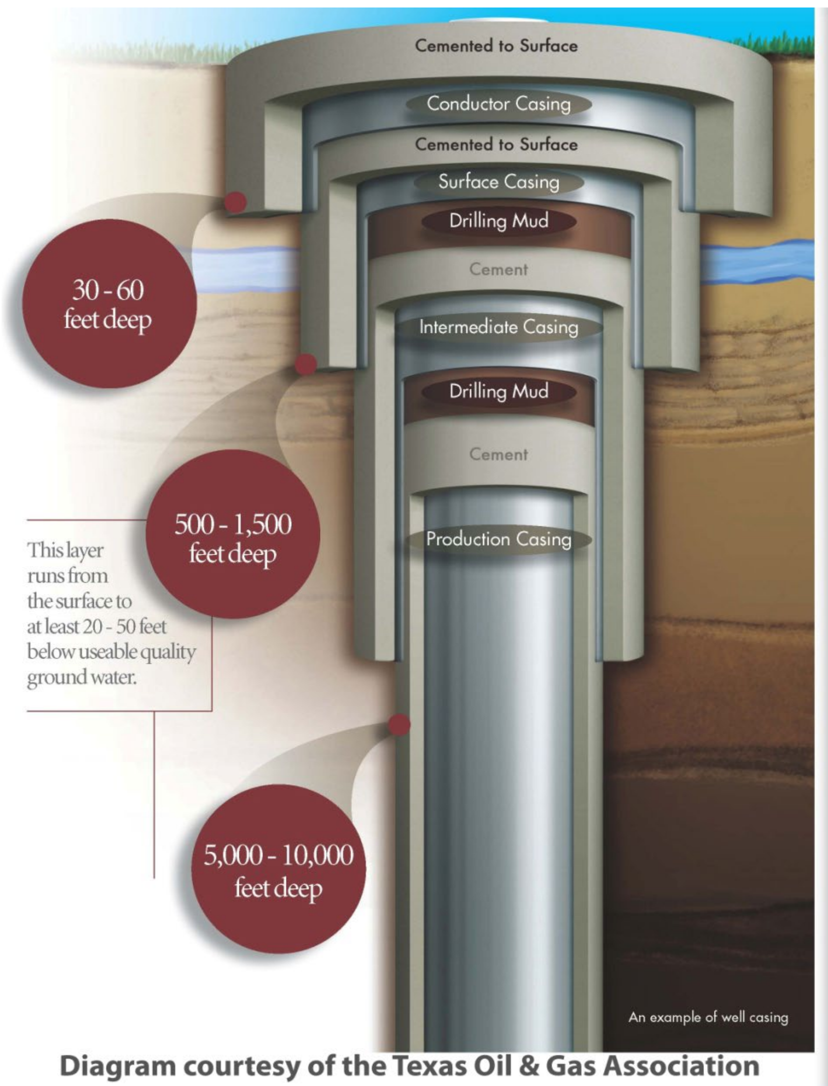

Figure 4-12 – Source Texas Oil & Gas Association

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 on 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 for surface and intermediate casing. Where appropriate, such as when the drill hole has deviated from vertical, casing centralizers are used to assure the casing is centered in the hole prior to cementing so that cement will completely surround the casing. An exaggerated (Not to Scale) cross-sectional diagram of a well equipped with casing and cement is shown in Figure 4-12.

Although some agencies require complete circulation of cement from the bottom to the top of the production casing, most agencies require only an amount of cement calculated to raise the cement top behind the casing to a certain level above the producing formation or other flow zones that may overlie the target reservoir. For example, in Arkansas, production casing must be cemented to 250 feet above all producing intervals.

There are a number of reasons why cement circulation from bottom to top on production casing is not typically required, including the fact that, in very deep wells, the circulation of cement is more difficult to accomplish. Cementing may be handled in multiple stages, but this 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. While there are differing views regarding bottom to top cementing of the production casing annulus, the presence of the un-cemented annulus does provide a means to evaluate the ongoing mechanical integrity of a well through annular pressure monitoring.

Some agencies also require the use of well tubing in addition to casing 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.

The Relationship of Well Integrity to Groundwater Protection

Casing strings are an important aspect of well integrity with respect to groundwater protection, providing for the isolation of protected groundwater zones. Casing is also used to isolate producing zones, pump fluids down the wellbore into the target reservoir during hydraulic fracturing stimulations, transmit flowback fluids from well treatment back to surface containment facilities, and to convey crude oil, natural gas, and produced water to surface during the productive life of a well. In this regard, surface casing is the first line of defense and production casing provides a second layer of protection for groundwater. As important as casing is, however, it is the cementation of the casing that adds the most value to the process of groundwater 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, including cement quality and placement, is perhaps the most critical factor in the prevention of fluid movement from deeper zones into groundwater resources. Cement quality can be affected by a number of factors, including:

- **Quality of the mix water:** The use of excellent quality water for cement mixing is very important because contaminants in the water (such as tannins from decaying vegetation) can affect the ability of the cement to harden;
- **Ratio of cement to water:** Proper setting of the cement depends on the use of the correct cement to water ratio in the mixture. Too little water and the cement will not pump properly; too much water and the cement will not harden properly. Water in excess of what is required to fully hydrate the cement is called free water. In technical literature, and in some cases in rule, typically a maximum free water amount is specified for each cement mixture;
- **Additives used in the cement:** There are dozens of oilfield cement types including standard Class A (neat) cement, Class H (high temperature) cement, Pozmix® (a mixture of fly ash and cement), and many others. Each is used under particular circumstances such as in deep wells, over-pressured wells, etc. There are also a wide variety of additives that can be blended with the various cement types to modify cement properties in response to site-specific conditions. For example, additives can prevent lost circulation, reduce, or increase slurry density, and accelerate or retard the development of compressive strength. Engineers design cement-additive blends for each application to ensure that the cement not only sets properly but has the correct characteristics and integrity to prevent fluid flow;
- **Curing time allowed:** Prior to drilling out the cement used to set the casing, it is important to allow it to cure properly. This is usually accomplished by establishing a minimum curing time for the cement. Failure to allow the cement to cure properly can cause cement failure or loss and lead to channeling of the cement behind the casing, which could result in fluid flow; and
- **Placement procedures:** Most primary cementing operations employ a two-plug cement placement method. After drilling through an interval to a desired depth, a crew removes the drill pipe, leaving the borehole filled with drilling fluid. A casing string is then lowered to the bottom of the borehole. As the casing string is lowered, the interior may fill with drilling fluid. This fluid must remain isolated from the cement because the fluids are typically incompatible and when in contact with one another can form a gel that may be difficult to remove from the pipe. Chemical washes and spacer fluids are usually pumped after the drilling fluid and before the cement slurry. Wiper plugs are also placed at the interface between the drilling fluid and the cement and between the cement and the displacement fluid to keep the fluids separated. When the bottom wiper plug hits bottom it allows the cement to pass through into the annulus and fill the backside of the casing. When the top wiper plug hits bottom, it remains and closes the hydraulic connection between the inside of the casing and the annulus. Proper cement placement means the primary cement job forms a hydraulic seal in the annulus and prevents the migration of fluid between zones.

Well Testing and Integrity Evaluation

In some agencies, it is common for state personnel to witness the running and cementing of casing strings; in others, the submission of a completion report detailing the amounts and types of casing and cement used in the completion of the well is considered sufficient evidence of proper well construction. Some agencies, including Michigan, Ohio and others, may require an additional verification method using geophysical logs such as Cement Bond Logs (CBL) and in some cases Variable Density Logs (VDL). By measuring the travel time of sound waves through the casing and cement to the formation, the CBL may indicate 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 may be determined. However, the API warns that "Caution should be exercised when using cement evaluation logs as the primary means of establishing the hydraulic competency of a cement barrier. The interpretations of cement evaluation logs are opinions based on inferences from down hole measurements. As such, the interpretation of cement evaluation logs can be highly subjective."[29]

There is no "silver bullet" method to effectively evaluate whether a cement job has met performance objectives. In addition to measurements recorded during each job and measurements of cement bonding, additional integrity tests can be made to determine whether there are migration pathways through the annular cement. Several cased hole geophysical logs can be used for this evaluation including:

- **Temperature logs:** Temperature logs measure a variation in temperature against a reference gradient. Variations from the gradient signal the movement of fluids into a borehole or flowing behind casing;
- **Noise logs:** A noise log is an acoustic log that measures sound behind casing, enabling a determination of whether fluid is flowing behind the pipe;
- **Radioactive Tracer Survey (RTS):** This tool uses a set of injectors and detectors to determine whether an injected tracer has moved from an injection point. If a radioactive tracer injected at one depth is detected at a shallower depth, it indicates an upward fluid flow behind the casing and
- **Oxygen activation log (O2):** O2 logs use the decay factor of oxygen activated by high-energy neutrons to produce an isotope of nitrogen which decays back to oxygen with a half-life of 7.1 seconds and produces a detectible gamma ray. Count rates are measured to determine the velocity, flow rate, and distance of water from the tool.[30]

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[29] American Petroleum Institute, *Isolating Potential Flow Zones During Well Construction*, HF 65-2, (Dec. 2010).
[30] *Oilfield Glossary*, SCHLUMBERGER, http://www.glossary.oilfield.slb.com/.

Certain geophysical logs are designed only to evaluate the cement behind the casing. Other means of demonstrating different parts of well integrity include formation integrity tests, casing pressure tests, and casing/tubing annular pressure tests. No single geophysical tool will work under all circumstances, and proper tool selection, calibration, and skilled interpretation are essential.

January 2021 Findings

Several elements related to well drilling, construction, and integrity are required to provide protection for groundwater resources. For example, while it is typical for operators to notify inspectors regarding the schedule for drilling a well, 11 states require a prior notification to the agency before well construction is undertaken. This notice increases the chances the agency will be able to have someone on site to witness the running and cementing of casing; which is a critical element in the protection of groundwater. The quality of the materials used in the construction of the well is also of great importance. In this regard seven agencies have requirements on the use of reconditioned casing and ten specify the casing must be rated for the conditions expected to be encountered during operation of the well. Further, 13 agencies have specific cement standards such as cement type limitations, requirements for use of API approved cements, limitations on free water content in cements and others. All of these numbers demonstrate increases from the 2017 report.

Perhaps the most critical element related to groundwater protection involves the running and cementing of surface casing. Because surface casing provides the first line of defense for groundwater zones and is typically run below the deepest protected groundwater aquifer it is very important to make sure it is run and set properly. In this regard 26 agencies in the study require that surface casing must be set below the base of protected groundwater and cemented from the bottom to surface. Also, 11 states prohibit the use of oil based muds, and ten prohibit non-freshwater drilling fluids for the surface casing portion of the well. Thirteen agencies require the surface casing be pressure tested prior to drilling out the cement. Further, eight agencies also require operators to set centralizers on the surface casing at appropriate intervals to ensure centering of the casing in the hole, which facilitates circulation of the cement completely around the casing string (a 37.5 percent increase since 2017). With respect to cement integrity, 22 agencies require the operator to wait a specified amount of time after cementing surface casing before proceeding with additional drilling. This "wait on cement" time insures that the cement has had time to cure to provide the best hydraulic seal behind the casing prior to "drill-out." In addition to specifying requirements for well construction and cementation, many agencies can require well integrity demonstrations. For example, 22 agencies can compel an operator to provide cement evaluation logs such as a CBL/VDL, temperature, noise, or other logs when it is deemed necessary to verify cement integrity and cement bond quality behind the casing. Figure

4-13 shows some of the surface casing, drilling, and construction requirements agencies use to insure well integrity and groundwater protection.

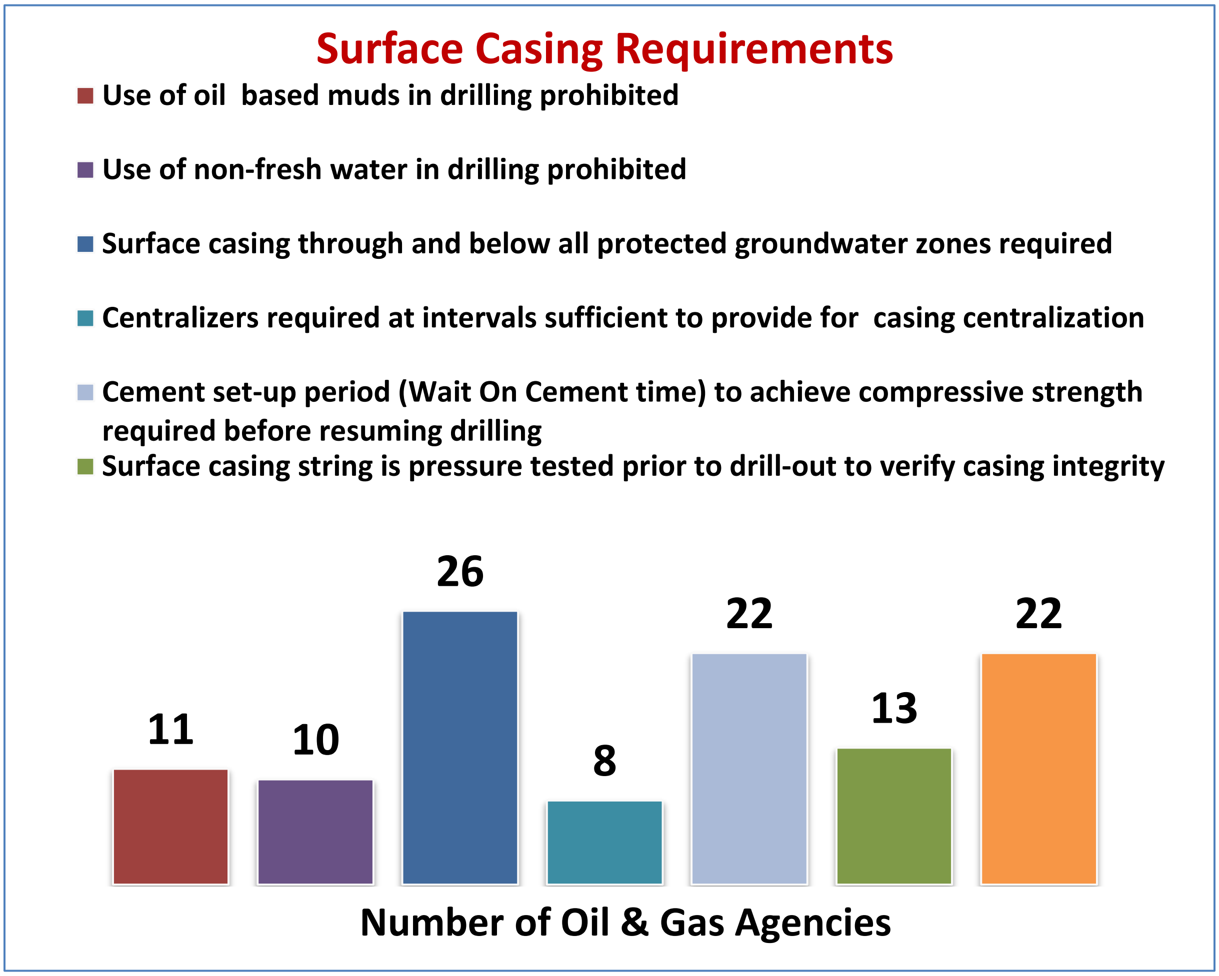

Figure 4-13

In addition to surface casing, many states require the setting of additional casing strings such as intermediate or long string casing to protect groundwater, oil, gas, and coal bearing zones, or to seal off high pressure or corrosive zones. For example, nine agencies require the use of intermediate casing in certain circumstances, while 18 require long string/ production casing.

Temporary Abandonment

Temporary abandonment (TA) is a state regulatory process that 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 (such as during periods of economic stress). This practice is common in many agencies. The primary purposes of allowing temporary abandonment are to prevent plugging wells that may have future economic value and to avoid drilling replacement wells.

TA Implementation

Nearly all states provide for TA as a means of holding a well in a legal status in the absence of production. In most agencies operators are required to notify the regulatory agency in advance of temporarily abandoning a well. In many cases the state agency may require an operator to either demonstrate that the well has mechanical integrity or that is it constructed and maintained in a manner that will prevent it from posing a risk to protected groundwater resources. Requirements can involve well testing, construction reporting, fluid level measuring, or other demonstration methods. Initial TA periods range from as little as one year to as many as five years. Twenty-six states allow an operator to renew TA status. However, many states place an absolute limit on the renewal period for TA, and several provide that the operator must attest to the future value of the well to obtain a renewal authorization. Although TA is a tool used to prevent the unnecessary plugging of wells with future value, it has unfortunately been used in some cases as a means of avoiding abandonment costs associated with plugging wells. Agencies are aware of this and are using tools such as a certification of future value for wells to prevent misuse of the TA process and avoid the addition of more wells to their orphan well inventories.

January 2021 Findings

Twenty-six agencies specify that an operator may temporarily abandon a well for various periods of time. Twenty six agencies also allow the operator to renew the TA status of a well and of these, 15 place a limit on the total duration of time a well may remain in TA status. Additionally, 17 agencies require that an operator either pressure test the casing or meet specific well construction standards as a condition of TA (See Figure 4-14).

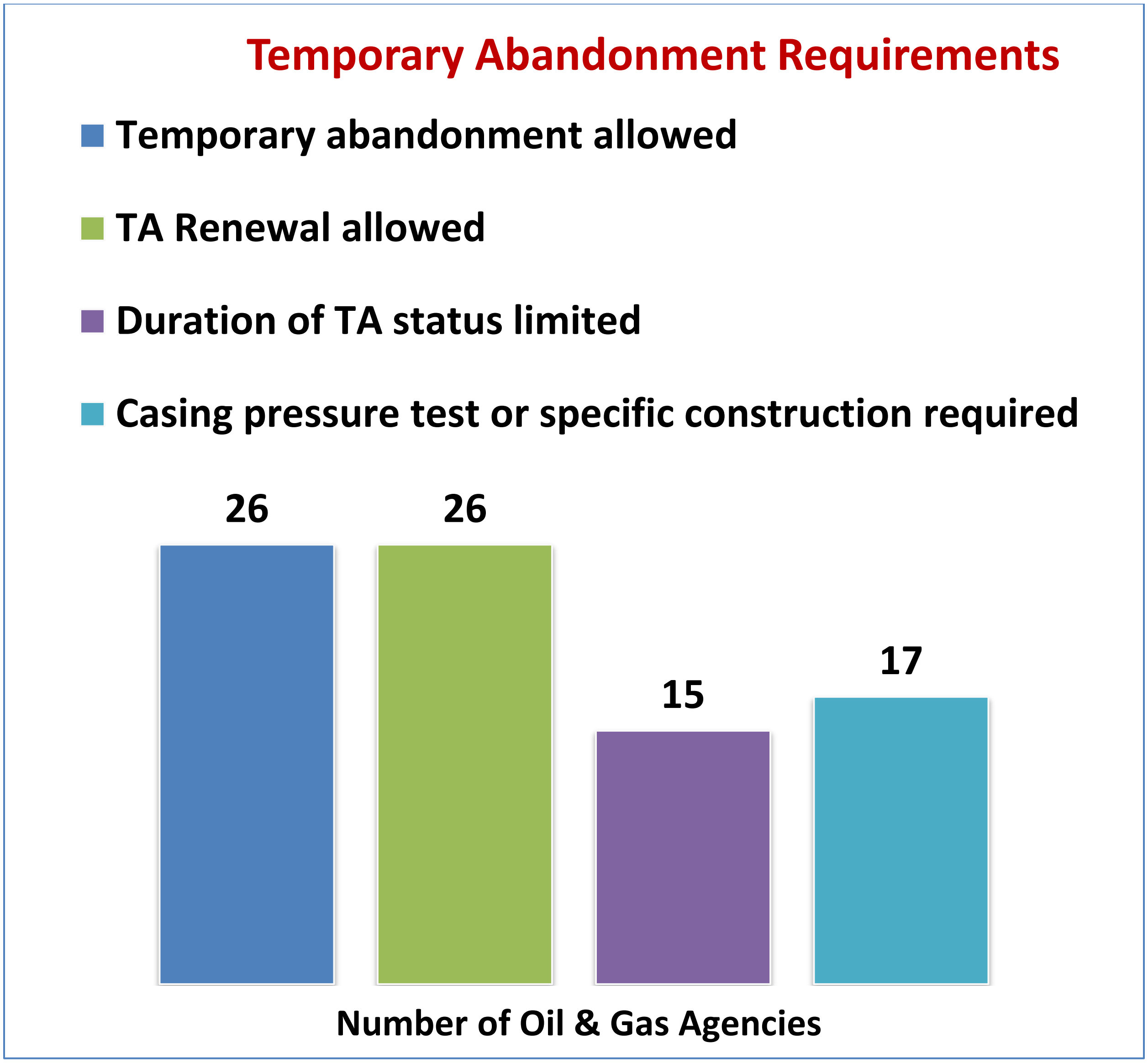

Figure 4-14

Production Operations

With respect to production operations the report covers three elements:

- Post-completion tubing, casing, or Braden head pressures;
- Piping, valves, and flow lines inspections by operators; and
- Inspections of other appurtenances (oil/ water separators, heater treaters, etc…) by operators.

Monitoring and Inspection

One of the ways to evaluate continuing well integrity is by monitoring the casing/ tubing or casing/casing annulus of a well. In those cases where casing strings are not cemented from bottom to top the annular space can be gauged so that changes in pressure can be assessed. These changes can be indicators of well barrier leakage and thus loss of mechanical integrity.

The most common cause of spills and leaks are failures in the piping, valves and flowlines that are used to transport oil and water. Monitoring these items via routine operator inspection can help ensure that leaks, when they do occur, are caught, and remedied before they can result in substantial environmental harm.

Operator inspection of equipment that is used to separate, treat, and store oil and water is another way to ensure that failures of equipment that result in leaks of oil or water are caught before they can result in substantial environmental harm.

January 2021 Findings

As of January 2021, seven states require operators to inspect or monitor the annular space between the casing and tubing, or between two casing strings (an increase of 43 percent since 2017). Further, six agencies require operators to inspect piping, valves, and flowlines (an increase of 33 percent since 2017). Finally six agencies require operator inspections of other appurtenances (an increase of 100 percent since 2017). While it should be noted that these items are typically inspected by the agency field inspection staff, operators would be more likely to perform more frequent inspections because they often assign staff to visit production facilities on a routine basis.

Storage in Pits

Proper management of fluids from well drilling, treatment and production operations is critical to the protection of water resources. With the advent of horizontal drilling and multi-staged hydraulic fracturing, the volumes of water being managed have increased exponentially. This has led to increasing concern about the risk of surface and near subsurface contamination related to fluid management especially as it relates to the use of pits.

Today, pits are used for storage of fresh water and produced water, for emergency overflow, temporary storage of oil, burn-off of waste oil, and temporary storage of well completion and treatment fluids. The three most common types of pits are drilling/ workover pits, emergency pits, and produced water storage pits.

- Drilling/workover pits are used to store the fluids used during the drilling process. These fluids are usually made up of fresh water and bentonite clay. However, in some locations, oil-based and produced water-based muds are still used due to specific drilling and formation conditions. Pit liners are normally not used in cases where drilling mud is primarily fresh water, but are usually required for other types of drilling fluid;

- Produced water storage pits are the largest type of pit and are used to store water that comes to the surface as part of the oil and gas production process. They are often associated with a Class II UIC disposal or enhanced recovery well. *NOTE: Twenty-five states regulate produced water storage pits, including some states that prohibit their use; and*
- Emergency pits are constructed to capture spills and leaks. They are usually required to be kept dry except during an emergency and are not usually lined.

Pit Siting and Construction

Many agencies limit the siting of pits based on such criteria as:

- **Distance to surface water:** In some agencies, pits may not be located within a floodplain or within the bound of the 100-year flood contour. In California, for example, pits may not be placed in areas considered "natural drainage channels." In other agencies, pits that are built within a floodplain must be constructed so that flooding will not result in water entering or leaving the pit. Many agencies require a minimum distance between surface water and the location of a pit; and
- **Distance to groundwater:** While some agencies specify how far the base of a pit must be above groundwater, others prohibit the excavation of pits into or through the depth of the seasonal water table. Still others have no restrictions regarding the siting of pits with respect to groundwater.

In 18 agencies, produced water storage pits must have a liner designed to prevent the downward movement of pit fluids into the subsurface.

Pits should be designed, constructed, maintained, operated, and closed in a manner that protects groundwater and surface water. Depending on the nature of fluids being placed in the pit, the duration of storage, and soil conditions, pit lining may be necessary to prevent infiltration of fluids into the subsurface. In 14 states, drilling pits must have a natural or artificial liner designed to prevent the downward movement of pit fluids into the subsurface. Eighteen agencies require liners for produced water storage pits. (an increase of 17% since 2017) For example, in Louisiana, liners are required for produced water, onshore terminals, and washout pits. In some agencies, 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. For liners to work properly they must be seamed in accordance with the manufacturer's instructions. In some agencies, pits are also required to have leak detection systems, which are designed to provide the operator with the means of determining the continued integrity of the liner. Eighteen agencies require fluids in produced water storage pits remain a certain level below the top of the pit wall (an increase of 22 percent since 2017). This distance, referred to as the "freeboard," provides for a safety margin to prevent pit overflows from significant rainfall.

Pit Operation

Routine inspections by the regulatory agency may include periodic placement of a pit's contents into tanks by the operator so examination by the agency and maintenance by the operator can be performed. This process is critical to ensure that a pit will not pose a threat to either surface or groundwater. In six states, both drilling/ workover and produced water storage pits must be inspected by a state field inspector before they may be put into operation. The operation of a pit requires the operator to maintain the integrity of the pit, monitor for leaks, maintain fluid levels below established freeboard minimums, and prevent the introduction of materials that would render the contents of the pit non-exempt under the Resource Conservation Recovery Act (RCRA) Subtitle C provisions. Although agencies do not typically require routine sampling and analysis of pit contents, oil and gas agencies typically hold the operator responsible if improper or illegal dumping of non-exempt waste into the pit occurs.

Pit Closure

After a pit has fulfilled its function and is no longer needed or authorized, it must be closed in a manner that will prevent pit contents and other materials from contaminating the soil or water. In drilling pits where fresh water and clay were used, closure is often accomplished by simply removing and properly disposing of the free fluids in the pit and burying of the pit residual solids within the pit. Where other types of drilling fluids were used, the fluids must be removed and properly disposed of, and remaining residual solids must be removed from the pit and either bio-remediated on-site or removed from the site and interred in an appropriate facility such as a special waste landfill. For example, Colorado Rule 905.b. (2), states that "prior to backfilling and reclamation, E&P waste must be treated or disposed," Colorado also requires confirmation soil sampling when pits are closed to demonstrate compliance with cleanup standards and liners can't be left in place even if shredded.

For pits with artificial liners, the typical procedure is to drain the pit and remove the liner, or drain the pit, shred the liner, and bury it within the pit boundaries. In either case, the removed fluids must be disposed of properly. In some agencies, the operator must file a pit closure report detailing the steps taken to close the pit and dispose of the contents.

January 2021 Findings

As in the 2017 edition of the report, for this edition we evaluated the two most significant categories of pits (drilling/ workover and produced water storage) independently. Consequently, the statistics listed here are specific to each type of pit.

Drilling/ Workover Pits

Pits used for the purpose of temporarily storing the fluids used in the drilling and well workover processes and their associated wastes are specifically regulated in 25 states. In 15 of these, the state oil and gas agency requires a prior authorization or permit. While five agencies have specific construction requirements; 20 have general requirements. Fourteen agencies require pit liners. Of these, ten require the liners to be artificial or synthetic but seven allow the use of natural liners such as clay. In 15 states the oil and gas agency has liner competency standards (an increase of 13 percent since 2017). Bed preparation standards are specified by ten agencies and 16 agencies require reporting of leaks. Nineteen agencies also require corrective action in response to leaks (an increase of 26 percent since 2017).

With respect to siting and setbacks ten agencies require a specific setback from surface water and also prohibit the excavation of pits into the water table. Twelve agencies limit the siting of these pits within the 100 year floodplain.

Twenty agencies limit the duration of use for drilling/ workover pits. Figure 4-15 shows some of the requirements relative to drilling/ workover pits.

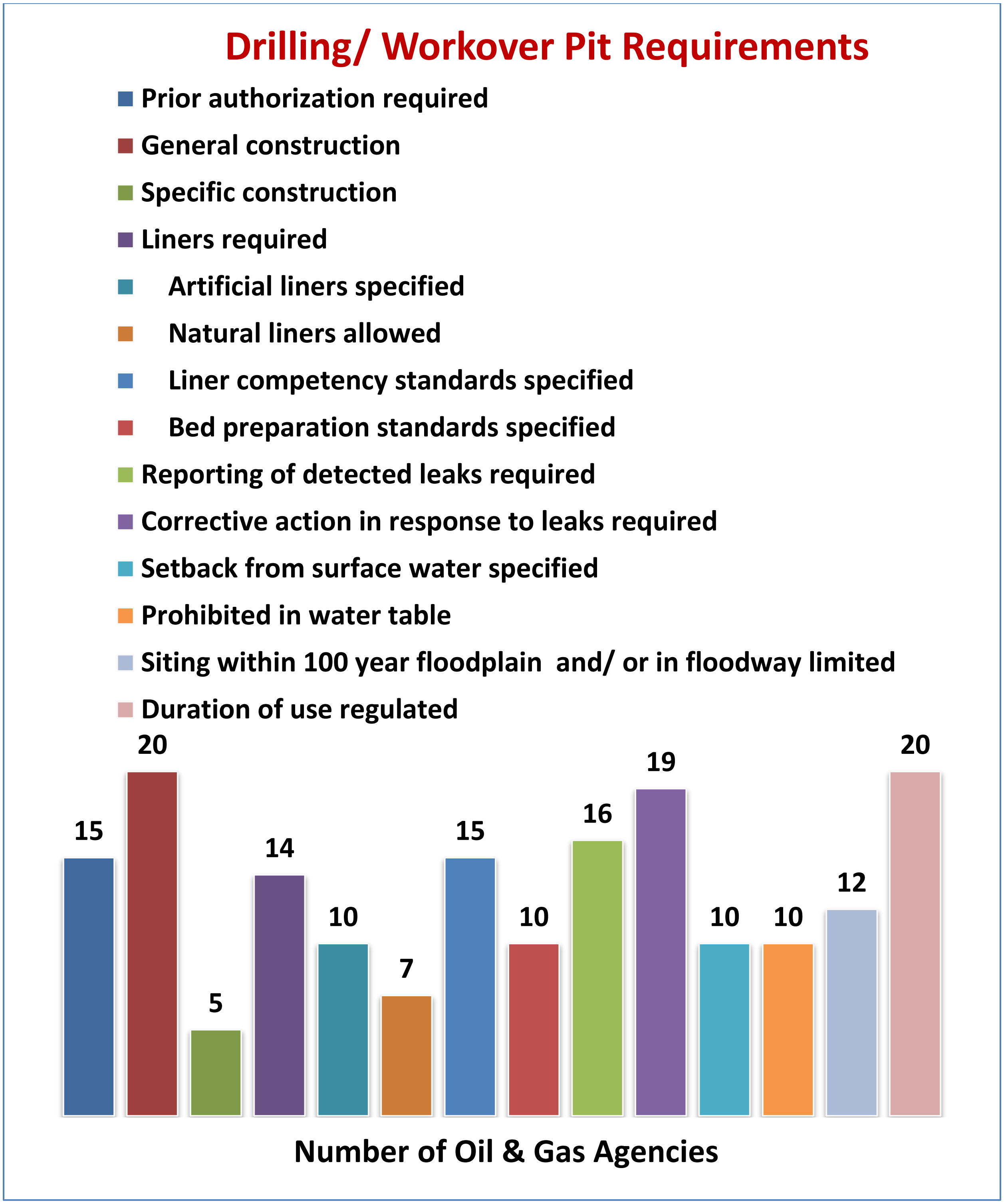
Drilling/ Workover Pit Requirements
Prior authorization required
General construction
Specific construction
Liners required
Artificial liners specified
Natural liners allowed
Liner competency standards specified
Bed preparation standards specified
Reporting of detected leaks required
Corrective action in response to leaks required
Setback from surface water specified
Prohibited in water table
Siting within 100 year floodplain and/ or in floodway limited
Duration of use regulated
15
20
5
14
10
7
15
10
16
19
10
10
12
20
Number of Oil & Gas Agencies

Figure 4-15

Produced Water Storage Pits

In 19 states produced water storage pits require a prior authorization or permit from the oil and gas agency. Whether or not a permit is required, seven agencies have specific construction requirements for these pits; while 16 have general requirements. Eighteen agencies require pit liners. (an increase of 22 percent since 2017) Of these, 12 require the liners to be artificial or synthetic while seven also allow the use of natural liners such as clay. One agency does not specify the liner type. In 15 states the oil and gas agency has liner competency standards (an increase of 20 percent since 2017). Bed preparation standards are specified by 12 agencies and 16 agencies require reporting of leaks. Sixteen agencies also require corrective action in response to leaks (an increase of 12 percent since 2017).

With respect to siting and setbacks, ten agencies require a specific setback from surface water and eight also prohibit the excavation of pits into the water table. Twelve agencies limit the siting of produced water storage pits within the 100-year floodplain. Figure 4-16 shows some of the requirements for produced water storage pits.

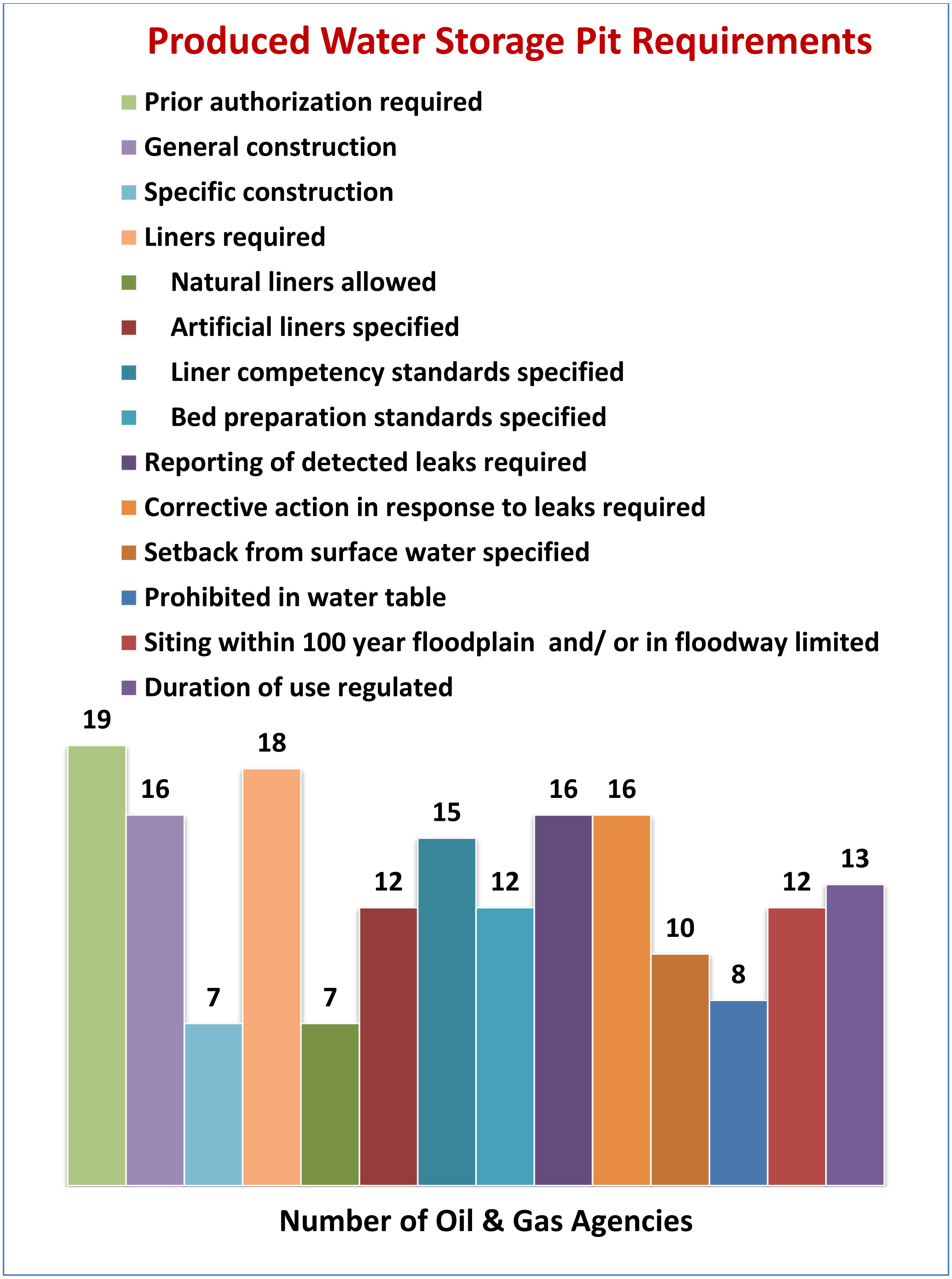
Produced Water Storage Pit Requirements
Prior authorization required
General construction
Specific construction
Liners required
Natural liners allowed
Artificial liners specified
Liner competency standards specified
Bed preparation standards specified
Reporting of detected leaks required
Corrective action in response to leaks required
Setback from surface water specified
Prohibited in water table
Siting within 100 year floodplain and/ or in floodway limited
Duration of use regulated
19
16
7
18
7
12
15
12
16
16
10
8
12
13
Number of Oil & Gas Agencies

Figure 4-16

With respect to produced water storage pits; 13 agencies limit their duration of use, and seven require a specific prior authorization for closure. It is important to note that although only 13 agencies have specific requirements regarding the disposal of pit contents, all 27 agencies have general produced water management requirements that include combinations of re-use and disposal of produced water. Eight agencies specify that the produced water storage pit sites must be returned to prior use conditions after closure. Six agencies allow produced water storage pits to remain open at the request of a landowner, but only one requires notification of a surface owner prior to closure.

Figure 4-17 shows some of the requirements relative to the closure of produced water storage and drilling/ workover pits.

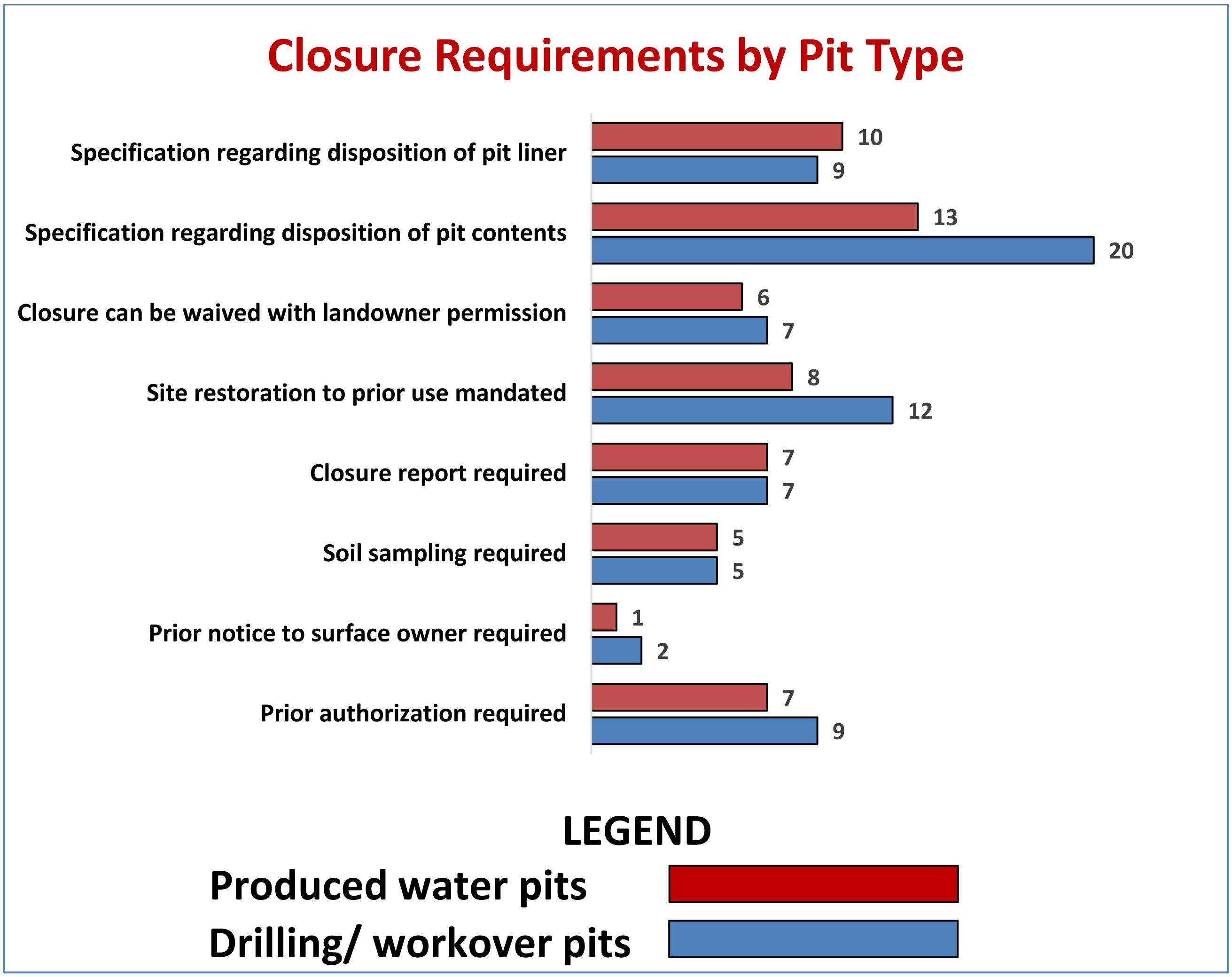

Figure 4-17

Storage in Tanks

Figure 4-18 Tank battery in northwest Oklahoma City - Source, GWPC

Tanks can be portable, such as the steel tanks used to capture drilling fluids and store water prior to hydraulic fracturing or those used as test tanks at a wellsite, or more permanent, such as the steel, fiberglass, and polyethylene tanks used to store produced water and oil prior to pick up. Tanks used for the storage of oil and produced water vary in material composition, placement configuration, and size depending on specific production needs. A group of tanks used to store oil and produced water is often referred to as a "tank battery." Where water is not co-produced with oil, the tank battery typically consists of one or more oil storage tanks. However, when saltwater is part of the production fluid stream, the tank battery also usually includes a vertical gravity oil/water separator, sometimes called a "gun barrel" and one or more water tanks for the storage of produced water that has been separated from the produced oil/water stream. In some cases, additional tanks such as heater treaters, which use heat to break down the oil/water emulsion, are also present.

For this report, tanks are defined as enclosed units fabricated off-site. Unlike pits, tanks provide a closed system for fluid storage. See Appendix 6 for a detailed comparison of risk management considerations for pits and tanks. Modular tanks assembled on-site are most-often open-top and have design and operational components in some respects similar to pits and in some respects similar to tanks. Modular tanks are discussed in more detail in "*Key Message 2: Emerging Issues*".

Tank Siting and Construction

Most agencies do not specify the materials to be used in the construction of tanks. However, seven agencies have tank construction requirements based on the specific fluids being stored, and one state, Colorado, requires operators to use tanks that meet Underwriters Laboratories (UL) or API standards, as applicable. In most agencies, the lack of a specific requirement such as an industry or technical standard 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 agencies, it is not uncommon for produced water to be stored in uncoated steel tanks. Since produced water is corrosive to varying degrees, storage in unlined steel tanks can lead to leaks and tank failures over time. In some cases, the use of cathodic protection is necessary to prevent metal oxidation with resultant degradation. Development of tank construction standards is evolving, and more agencies are beginning to review their current standards with an eye toward implementing additional requirements. For example, Alabama and Florida require operators to follow "generally accepted industry practices and standards", Michigan requires pre-construction plans to be submitted to the oil and gas agency, and New York requires that tanks be "watertight".

Figure 4-19 Secondary containment structure- Source, ©2014 Falcon Technologies and Services, Inc. All rights reserved.

In part, because tanks may be more likely than pits to fail in a catastrophic manner and release their total contents in a single event, the use of secondary containment designed to hold the contents of entire tanks, or interconnected tank systems, is commonplace. These containment structures may sometimes be referred to in regulations as firewalls And while they serve the purpose of containing tank fires, their principal purpose is to contain fluids from tank failures or leaks (See figure 4-19). Capacities of containment dikes typically range from one to one and a half (examples: Illinois and Indiana) to two (example: Florida) times the capacity of the tank or tanks surrounded by secondary containment.

Tank Operation and Maintenance

The operating physics of tank battery systems has remained essentially unchanged for more than 160 years. Most of the work of moving fluids from one tank to another, and for separation of oil and water, is managed by gravity. The oil/water emulsion is placed into a separator, which is a vertical or horizontal tank designed to divide oil, water, and gas from a column of produced fluids. After separation, the oil and water are stored in separate collection tanks. Today, these tanks are typically made of steel or fiberglass, although older tanks may have been made of concrete or even wood. Management of fluid flow through the tank system is complex and involves many simultaneous processes that must remain in balance for the system to work properly. A properly constructed and maintained tank battery can last decades. It is important that it is maintained over the life of the system so that leaks, spills, and tank failures do not occur.

Tank Removal

After a tank has reached the end of its useful life, it must be removed from the site so that it does not pose an environmental or safety hazard. Steel tanks are most often re-used or cut up and sold for scrap while fiberglass tanks are re-used or cut up and disposed of in landfills. Removal of the tanks often leaves behind some contaminated soil at the tank battery site. If this soil is highly contaminated, it may have to be removed and disposed of properly, usually by interment in either a sanitary or special waste landfill depending on the level and nature of the contamination. In some cases, the soil is capable of being remediated on-site using procedures similar to those used for oil and produced water spills. This may include either natural attenuation or active bioremediation using disking of the soils and the addition of nutrients, lime, and fresh water. The remediation methods allowed, and the final remediation level required are determined by each state regulatory agency. In several study agencies, including Alabama, Indiana and Mississippi, tank battery sites must be remediated, or the materials disposed of in accordance with specific requirements.

January 2021 Findings

As of January 2021, the regulation of tanks had not changed substantially from that reported in 2017. The lack of overall tank regulations remains an issue with respect to the potential impacts of their use. For example, as of January 1, 2021, seven oil and gas agencies had design and construction standards for tanks and one utilized an external standard such as an ASTM, International (formerly the American Society for Testing and Materials), American National Standards Institute (ANSI) or API standard for tank construction. Seven agencies also require tanks maintain a setback from either surface water or floodplains and five agencies require operators to conduct routine tank inspections. Regardless, secondary containment provisions continue to provide some assurance of environmental protection. In 22 states secondary containment surrounding tanks is required (an increase of 14 percent since 2017) and of these 18 require the operator to inspect and maintain the containment system. Additionally, 19 agencies require the secondary containment area be kept free of standing fluids so it can serve the purpose for which it was constructed. Figure 4-20 shows some of the requirements for tanks and secondary containment systems.

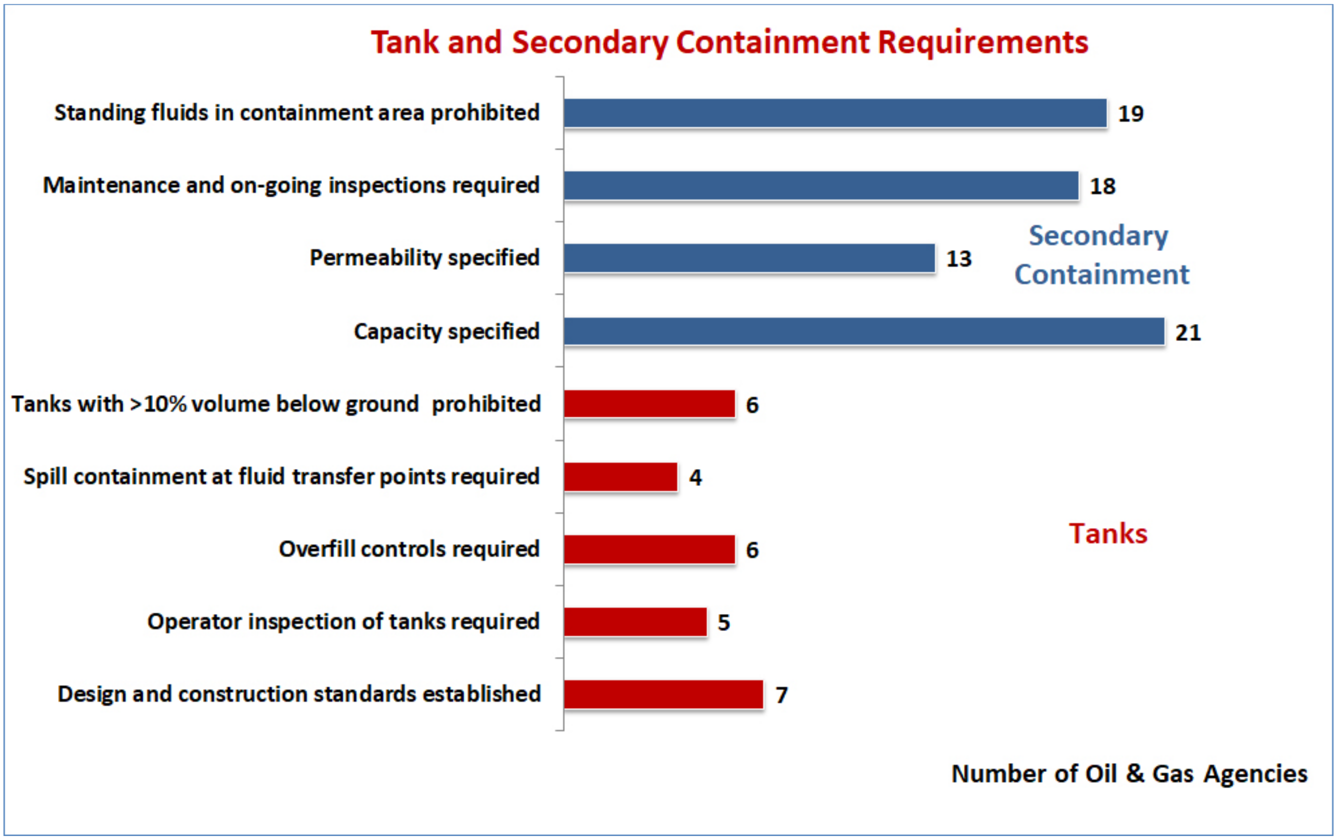

Figure 4-20

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 and mud inside the well or wellbore in a manner that prevents the upward or downward migration of formation fluids.

Materials

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. Because 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

Because the purpose of well plugging is to seal the wellbore, the competence, placement, and verification of plugs are critical 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, when in contact with water, they do not swell in the presence of petroleum. Consequently, in most cases agencies will typically allow clay to be used as a spacer between cement plugs, but not as a primary plugging material. Cast iron bridge plugs (CIBPs) provide a good well seal, especially when there is significant bottom hole pressure. CIBPs are also nearly impermeable, but they 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.

Intervals and Methods

Most agencies require a combination of plugs at multiple vertical intervals to ensure long-term protection from fluid migration and to compensate for various downhole geologic and hydrogeologic conditions that might render the plugging materials ineffective. Twenty-four agencies require the placement of a cement bottom plug through and/or above producing formations and the placement of a top plug across the deepest groundwater zone. Additionally, 20 agencies require the pulling or cementing in place of uncemented casing to assure cement is in contact with either the wellbore or cemented casing. Fourteen agencies also require that cement plugs be placed using a specific method such as the pump and plug (displacement) method or via dump bailing. Both methods are designed to spot plugs over particular intervals and to ensure 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 under certain conditions, though not specifically prohibited in most agencies, 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.

Reporting

Plugging reports typically 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.

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 agencies, 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.

Reports are typically submitted to the regulatory agency and placed in the well file as a permanent part of the record. These reports provide valuable information about the current condition of the well and are often used by the agency during other permit reviews such as those for injection wells.

January 2021 Findings

As of this report, 23 agencies regulate the timeline of when a well must be plugged. In most cases this involved establishment of a time limit following drilling or after a well became inactive. All 27 agencies require that an operator provide a notice of intent to plug and 21 require the submission of a plugging plan to the agency prior to commencing plugging operations. This provides the agency the opportunity to witness plugging. In eight agencies the witnessing of plugging operations is required by regulation (an increase of 25 percent since 2017). Six agencies allow for the submission of cement tickets or other verifiable documentation to demonstrate plugging where witnessing does not take place. Although 16 agencies specify the plugging method, only eight require the use of pump and plug or displacement methods for plugging of a well, while two specifically prohibit the use of dump bailing or bullhead (top down) plugging. This means that even though pump and plug may be listed or preferred, other plugging methods are acceptable under certain circumstances or conditions. In 23 agencies the regulations specifically state the location, thickness, and types of plugs. Nineteen agencies, require placement of bridge plugs under specific circumstances (an increase of 10% since 2017). Eighteen agencies also specify the types of cement that can be used to plug a well including nine that require cements meeting API standards. Figure 4-21 shows some of the elements related to the physical requirements for well plugging. It is important to note that while only 19 agencies require cement placement across "all" protected groundwater zones, all 27 agencies require placement of cement across at least the deepest protected groundwater zone.

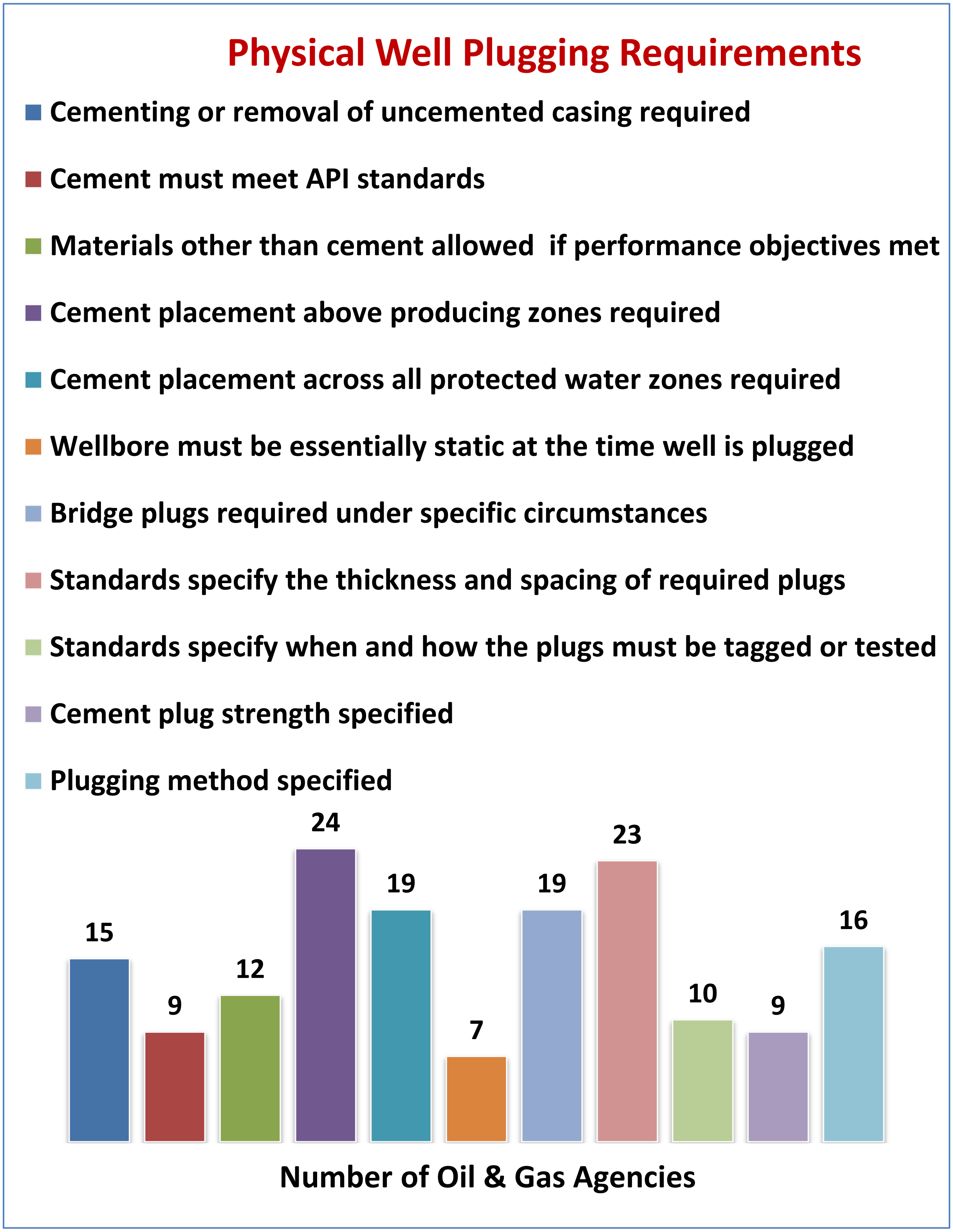
Physical Well Plugging Requirements
Cementing or removal of uncemented casing required
Cement must meet API standards
Materials other than cement allowed if performance objectives met
Cement placement above producing zones required
Cement placement across all protected water zones required
Wellbore must be essentially static at the time well is plugged
Bridge plugs required under specific circumstances
Standards specify the thickness and spacing of required plugs
Standards specify when and how the plugs must be tagged or tested
Cement plug strength specified
Plugging method specified
15
9
12
24
19
7
19
23
10
9
16
Number of Oil & Gas Agencies

Figure 4-21

All 27 agencies reviewed require an operator to file a report following the plugging of a well. These reports typically contain information about the plug placement intervals, plug types, perforations, casing left and plug placement methods among others. For example, 25 agencies require the operator to report the amount of casing left in a well. Twenty two require the report to include the volume of cement used in the plugging process and 18 also require a listing of the type of cement used by class such as Class A, C, H, etc. (increases of 18 percent and 22 percent respectively since 2017). The post plugging reporting requirements, reviewed for this report are shown in Figure 4-22.

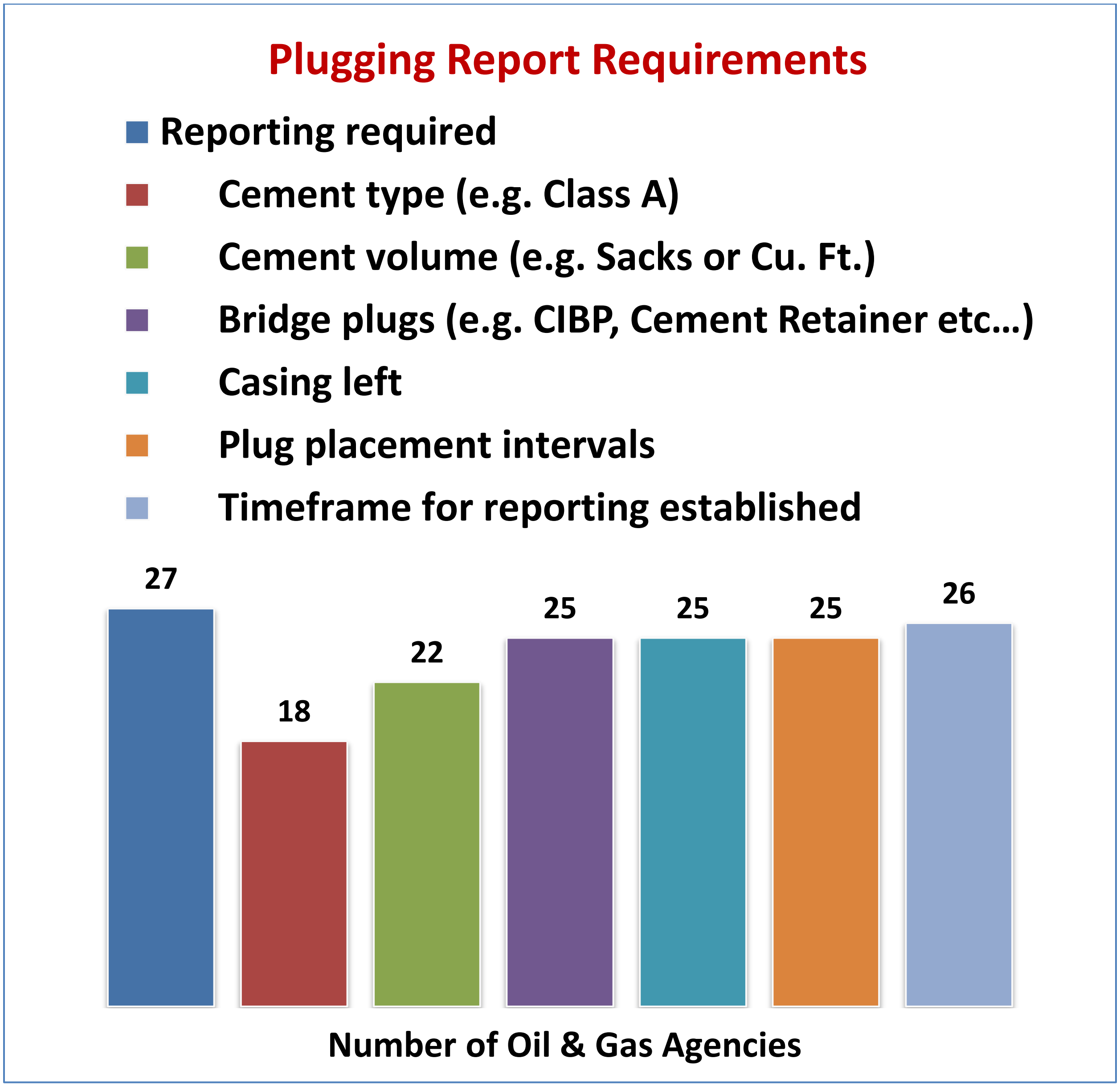

Figure 4-22

Transportation of Produced Water by Truck or Pipeline for Disposal

Produced water is the water that comes to the surface as part of the oil and natural gas producing process. In this report, it includes both natural formation water and the flowback water from hydraulic fracturing. Produced water is typically more saline than fresh water with TDS contents ranging from less than 1,000 parts per million (ppm) TDS in some coalbed methane zones, to more than 200,000 ppm TDS in some deep oil and gas zones. For comparison purposes, seawater contains about 35,000 ppm TDS. In addition to TDS, produced water may contain other constituents including organic compounds, metals, suspended solids, various cations, and anions, and naturally occurring radioactive material (NORM). While not covered in the original 2009 report, the subject of produced water and its transportation, use, storage, and disposal were added to the regulatory review in 2014.

Produced water is typically transported by truck unless a nearby disposal or enhanced recovery project is available to accept the water, in which case it is often transported via pipeline. As more options for managing produced water become available, other transportation options are being implemented, including transport via pipeline (either permanently installed or temporary laid on the ground surface). With recycling and reuse of produced water becoming more common, produced water is increasingly transported off-lease to either a storage facility to await further processing (which would entail additional transport) or to a treatment facility. From a treatment facility, the treated produced water would be transported again to a storage facility to await further handling or to a location where the fluid is reused in subsequent well completions. In all these instances, transportation can be accomplished via truck, pipeline (permanent and/or temporary), or even via rail or watercourse. With increased storage and transportation requirements come increased risks of spills and leaks from trucks, pipelines, and other containers or transportation mechanisms, underscoring the importance of regulations and operator practices aimed at minimizing these risks. In addition, states are increasingly interested in tracking and gathering data regarding changing practices for the management of produced water.

January 2021 Findings

Eleven oil and gas agencies require a prior authorization or permit for the transport of produced water either by truck or pipeline (an increase of 18 percent since 2017). Thirteen agencies require the operator to maintain a manifest or record of the volumes of water transported and 16 required the final disposition of the water be tracked (increases of 23 and 19 percent respectively since 2017). Figure 4-23 details the requirements for produced water transport reviewed for this report.

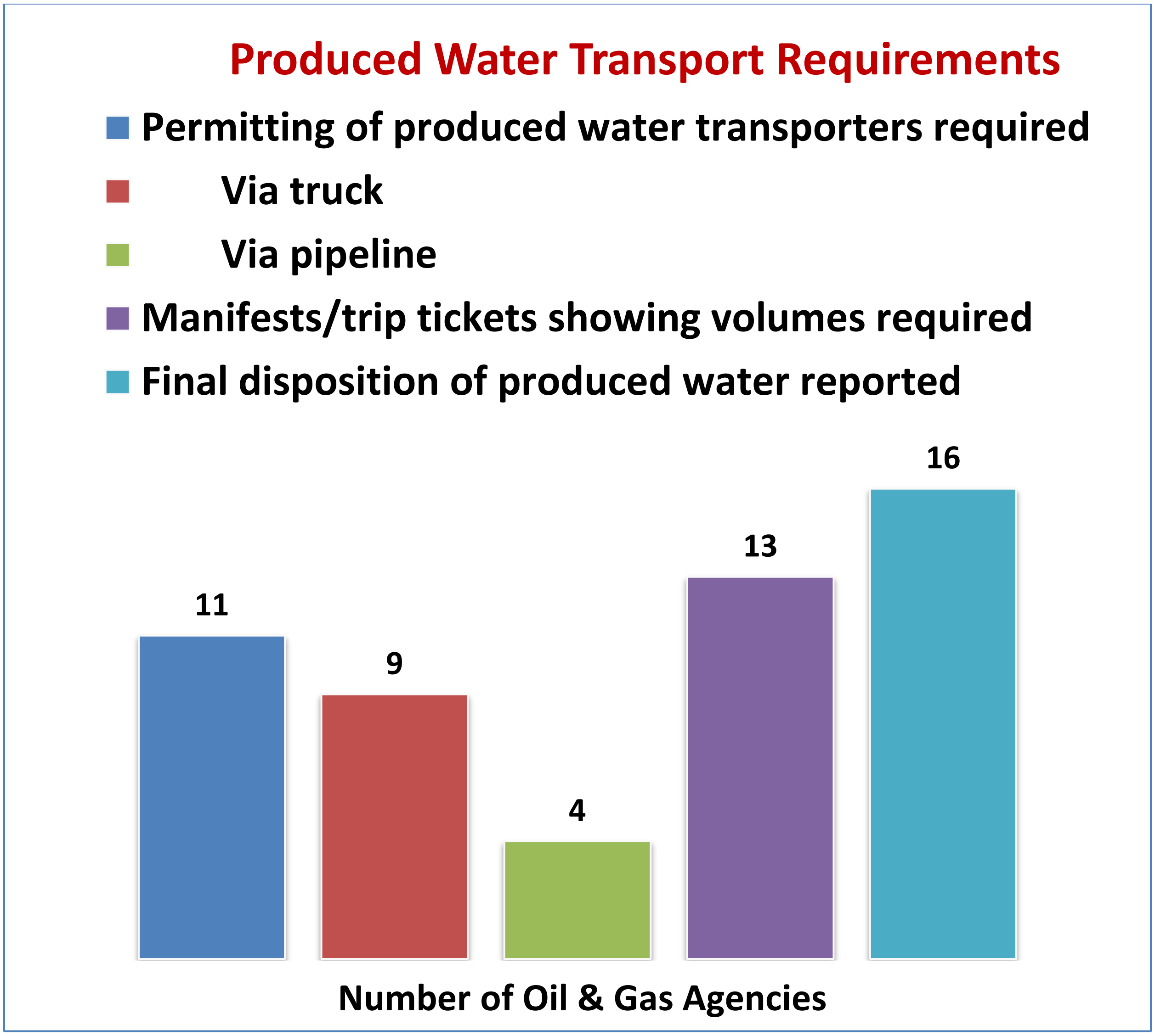

Figure 4-23

Produced Water Reuse for Oil & Gas

Fluid recycling continues to be a prevalent trend in the oil and gas industry. Not only does fluid recycling and reuse lower costs in some cases, but it also lowers the amount of new water that must be obtained to conduct well drilling and completing operations, and decreases the overall amount of fluid requiring disposal. A primary factor in the increased use of fluid recycling has been the large volume of water that is typically necessary to conduct multi-staged hydraulic fracturing operations in horizontal wells. As the volumes of fluid needed to conduct fracturing operations dramatically increased and new shale gas plays were developed, the ability to acquire water of suitable quality to conduct these operations became more problematic. Water usage depends on many factors including the shale involved, lateral length, and fracture design. For example, water usage in the Marcellus in Pennsylvania has been recorded to range from 2 to 4 million gallons per fractured well, while water usage in the Delaware can range from 3 to as much as 40 million gallons.[31] In the past few years the volumes of water used in hydraulic fracturing have increased substantially nationwide. For example, a high volume hydraulic fracturing job in 2017 may have used as much as 10 million gallons of water while a high volume hydraulic fracturing job in 2021 could use as much as 40 million gallons of water. Drought conditions in some regions of the country such as the southwest have added to the difficulties of acquiring new fresh water and made the use of produced water recycling a viable alternative. In some cases, regulatory authorities such as the Susquehanna and Delaware River Basin Commissions became involved in the process of authorizing water use for hydraulic fracturing, creating a new regulatory dynamic and making fluid recycling even more attractive. In Pennsylvania, the lack of nearby Class II disposal wells for injecting flowback water and associated transportation costs to injection wells in neighboring agencies has also incentivized development of recycling and reuse technology.

The advent of fluid recycling has created a new set of challenges. Larger volumes of fluids have to be managed on-site, treatment systems have to be constructed and maintained, fluid treatment residuals and by-products have to be disposed of, and new piping and transport systems between the wells and the treatment facilities have to be built. These new practices of managing produced water at the purpose for longer periods of time and at higher volumes also increases the risk of spills and leaks from storage and transportation. In some agencies, such as the Railroad Commission Texas, regulations have been developed to regulate and facilitate the practice of oilfield recycling.[32] The Texas regulations address storage in pits, disposal methods, management of waste haulers, and the use of commercial versus non-commercial facilities for recycling. Other agencies, such as Ohio, have passed legislation requiring entities to have a permit before they can store, treat, process, or recycle produced water, and authorizing the chief to adopt rules for the construction and operation of such facilities. Other states have adopted rules to address newer forms of high-volume storage such as above ground modular tanks.

On-site treatment and reuse of fluids using smaller portable water treatment systems is also becoming popular in more rural areas. These systems work well for small volumes of fluids (dependent on the level of treatment required) and are usually fully self-contained so that treatment by-products are kept within the unit until their proper disposal can be accomplished. The treatment and reuse of produced water is becoming more prevalent and is being addressed by groups such as the New Mexico Produced Water Research Consortium[33]. On-site treatment

[31] GWPC, Data gathered from well disclosure reports on FRACFOCUS, http://fracfocus.org/.
[32] Texas Railroad Commission Rule 8; 16 TEX. ADMIN. CODE § 3.8 (2013).
[33] New Mexico Produced Water Consortium, https://nmpwrc.nmsu.edu/

was included in the 2013 and 2017 reports but warrants a more in-depth review of current regulatory programs and is discussed further in the "*Key Message 2: Emerging Issues*" section of this report.

January 2021 Findings

Eleven agencies prohibit the use of produced water in drilling muds or fluids when used to drill the surface casing portion of a well. With respect to produced water pipelines, four agencies require the permitting, reporting, or siting of pipelines (a decrease of 33 percent since 2017). Of these, three require a permit or authorization, and one has specific siting requirements. Three agencies have specific design, construction, and operational requirements for produced water pipelines, including two that require an initial integrity test prior to use. Four agencies require routine integrity assessments during use. Two agencies require an operator to re-inspect and test a pipeline after repairs are made but prior to resuming operations. One also requires the decommissioning or removal of produced water pipelines. *NOTE: While most of these numbers are less than those reported in 2017, they represent figures that were verified for this edition of the report by all 27 state agencies.*

Exempt Waste Disposition

Wastes such as drill cuttings and tank bottoms typically require a different disposal strategy than produced water. While some wastes, such as drill cuttings, can be disposed of using underground injection, the primary disposal methods for such wastes may include onsite burial, off-site transport and burial in solid waste landfills, reuse for road base material or dust suppression, or bioremediation using land-farming techniques. However, some wastes may contain metals and other constituents at concentrations that make their reuse or on-site remediation problematic. The determination as to whether a waste is RCRA Subtitle C exempt is based on several criteria. However, with respect to oil and gas wastes the most commonly used rule of thumb is if a waste is "intrinsically derived from primary field operations associated with the exploration, development or production of crude oil and natural gas" it is typically considered Subtitle C exempt. In most cases, such wastes retain their exempt status. However, where an exempt waste is mixed with a listed hazardous waste, the resulting mixture is no longer exempt, and becomes subject to the RCRA Subtitle C provisions. Additionally, where an exempt waste is mixed with another, non-exempt hazardous characteristic waste, and the resulting mixture exhibits hazardous characteristics, the mixture is no longer exempt and becomes subject to the RCRA Subtitle C provisions.[34]

[34] EPA Office of Solid Waste: Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations, EPA/ 530K-01-004.

Management of Wastes

Surface management and land application of oil and gas E&P wastes is often regulated by multiple state agencies. For example, the Wyoming Oil and Gas Commission regulates the application of waste to land if the application occurs on a lease. However, off the lease, the same process is regulated by the Wyoming Department of Environmental Quality. Similarly, in North Dakota, remediation of small amounts 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 Environmental Quality. In Alaska, while subsurface disposal of E&P wastes is regulated by the Alaska Oil and Gas Commission, surface application and disposal of wastes such as tank bottoms is under the jurisdiction of the Alaska Department of Environmental Conservation.

There are numerous methods of waste disposition. For example, roadspreading of some E&P wastes is one method of on-site management that is commonly allowed in multiple states. This technique is typically limited to the application of drilling wastes such as cuttings and tank bottoms, which are primarily sand but may contain up to 19 percent oil by volume.[35] One concern raised by the road application of waste is the potential contamination of surface water sources due to dispersion of these wastes into roadside ditches. 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."[36] 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."[37] Although there is little that can be found in the literature after 2000 regarding the general environmental risks of spreading tank bottoms on roads or lands, risks associated with the presence of Technically Enhanced Naturally Occurring Radioactive Material (TENORM) in tank bottom sludge is one area of waste management that EPA is reviewing.[38]

January 2021 Findings

The disposition of waste can be broken down into several sub-categories depending upon factors such as the nature of the waste and the location of a waste application. For purposes of this report, we will divide the regulation of waste disposition into four sub-categories:

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[35] EPA Office of Compliance Sector Notebook Project: Profile of the Oil and Gas Extraction Industry, EPA/310-R-99-006 (Oct. 2000).
[36] EPA, Office of Solid Waste, Associated Waste Report: Crude Oil Tank Bottoms and Oily Debris (Jan. 2000).
[37] EPA, Office of Solid Waste, Associated Waste Report: Completion and Workover Wastes (Jan. 2000).
[38] https://www.epa.gov/radiation/tenorm-oil-and-gas-production-wastes

- On site disposal;
- Application of produced water to roads or lands;
- Application of tank bottoms to roads or lands; and
- On site disposal or re-use of drill cuttings.

On-site disposal

On-site disposal of oil and gas waste is regulated by 21 oil and gas agencies. Of these 13 require a permit to dispose of waste on-site and 19 regulate which specific wastes can be disposed of on-site. Sixteen of the 21 agencies with regulations require that the location of the disposal be reported to the agency, (an increase of 25 percent since 2017), and one of the agencies specifically prohibits on-site disposal.

Application of produced water to roads or lands

Seven agencies require a permit for application on roads and six require a permit for application to lands. Of those requiring a permit for road application three specify an application rate and four require reporting of the quantities applied. In eight agencies the application of produced water to roads is specifically prohibited (an increase of 25 percent since 2017). A similar pattern exists for application of produced water to lands. Six agencies require a permit for land application; four specify application rates and five also require reporting of quantities of material applied. Eight agencies specifically prohibit the application of produced water to lands.

Application of tank bottoms to roads or lands

The application of tank bottoms to roads or lands is regulated similarly to that of produced water application to roads or lands. In seven states a permit is required to apply tank bottoms to roads and of these five agencies specify an application rate, two require reporting of the quantity of material applied, and five specifically prohibit the practice. With respect to the application of tank bottoms to lands, seven agencies require a permit for application, six specify an application rate, and four require reporting of the quantity of material applied. Six agencies specifically prohibit the application of tank bottoms to lands (an increase of 33 percent since 2017).

On-site disposal or re-use of drill cuttings

Nineteen states regulate the practice of on-site drill cuttings disposal including one agency which prohibits the practice. Eleven agencies regulate the re-use of drill cuttings.

Spill Response

Spills of oil and gas products and wastes on a lease can occur under a variety of circumstances, including leaks from flowlines, wellheads, tanks, and pits. Off lease spills are not discussed here, as they include spills of tank trucks, etc., and are often regulated by agencies other than the oil and gas agency. Although many 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 several states, jurisdiction over a spill depends on factors such as the location and volume of the spill and the affected environmental media. In at least four agencies, spills are managed under split jurisdiction. For example, 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. In Indiana, spills of oil or produced water in soils that do not reach waters of the state are managed by the Indiana Department of Natural Resources (IDNR), Division of Oil and Gas, while spills that enter waters of the state are under the jurisdiction of the Indiana Department of Environmental Management (IDEM).

Spill Reporting

Requirements for reporting a spill of oil and gas products or wastes are often dependent on the nature, location, extent, and volume of a spill. In many cases, when a spill is contained within a secondary containment structure, does not leave the lease, or enter surface water, or is small (< 1-5 barrels), the reporting of spills is made only to the oil and gas regulatory agency. Otherwise, spill reports are typically made both to the oil and gas agency and to the state environmental regulatory agency. In most cases, both verbal and written notices are required with different timeframes for reporting. In a few cases, state regulations require an operator to also report the spill to the landowner.

Remediation/Disposal

In some cases, oil spills can be managed on-site using land-farming or bioremediation techniques. While bioremediation is not a cure-all, it can be used to successfully remove oily materials from a soil matrix. For example, in Indiana, the Division of Oil and Gas utilizes a formal Spill Management Guide as a manual to implement cleanup requirements that includes a bioremediation option.

The success of bioremediation depends upon several factors including:

- **Microbial community:** For bioremediation to work the proper community of microbes must be present in the soil.[39] *NOTE: Microbial augmentation has been used when such communities are absent or limited;*
- **Oil matrix:** Bioremediation has a higher success rate for lighter organics; whereas heavier organics such as asphaltenes are less amenable to this technique;
- **pH balance:** Maintaining a pH of between 6-9 is important to microbial health;
- **Soil matrix:** The composition of the soil as it relates to organic matter as a fraction of the soil can affect biodegradation;[40]
- **Hydration:** Maintaining a proper level of water content in the soil facilitates microbial community growth because the microbes live in the interstitial water in the soil pores;
- **Temperature:** Generally speaking, higher ambient temperatures positively affect oil eating microbes while lower temperatures impede them. *NOTE: However, as has been demonstrated in bioremediations projects in Alaska, lower temperatures do not prohibit the use of bioremediation*;[41]
- **Nutrition:** The addition of appropriate nutrients can assist microbial growth and improve their effectiveness because nitrogen and phosphorus are necessary for cellular metabolism and can be found in low concentration in many soils; and[42]
- **Aeration:** Periodic tilling of the soil improves oxygen content; which can affect microbial utilization of hydrocarbons.

Spills of produced water tend to be more damaging to soils and vegetation than oil spills. Produced water has the capability of damaging the soil matrix resulting in soil compaction. Further, the salt content of produced water is typically sufficient to cause damage to sensitive vegetation such as food crops and trees, and produced water usually contains other substances of concern as well. Additionally, the sodium absorption ratio (SAR) of soils impacted by produced water can be sufficiently high to prevent vegetative growth.[43] To deal with the issues of spilled produced water some agencies have guides for in-situ remediation of saline soils.

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[39] NRT Fact Sheet: Bioremediation in Oil Spill Response, USEPA, https://www.epa.gov/sites/production/files/2013-07/documents/nrt_fact_sheet_bioremediation_in_oil_spill_response.pdf

[40] Owabor, C.N. and O.F. Ogunbor, 2007. Naphthalene and pyrene degradation in contaminated soil as a function of the variation of particle size and percent organic matter. Afr. J. Biotechnol., 6: 436-440.

[41] Alain Ladousse and Bernard Tramier (1991) Results of 12 Years of Research in Spilled Oil Bioremediation: INIPOL Eap 22. International Oil Spill Conference Proceedings: March 1991, Vol. 1991, No. 1, pp. 577-581.

[42] Pritchard, P.H. and F.C. Charles, 1991. EPA's Alaska oil spill bioremediation project. Environ. Sci. Technol., 25: 372-379.

[43] *See generally,* Kerry Sublette, *Remediation and Restoration of Hydrocarbon and Brine Contaminated Soils* (Oct. 2013).

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Twenty-five oil and gas agencies implement some regulation relative to spills of liquids such as produced water and oil. The regulations range from management of the spill and cleanup specifications to spill reporting requirements. In all twenty-five agencies spills must be reported under differing circumstances including the location, volume, and nature of the spill. For example, in 19 states there is a volume threshold for reporting, and spills under the threshold may not require reporting except under certain circumstances such as a spill into water. All 25 agencies also specify the time limit within which an initial spill report must be made to the agency and 23 require a follow-up notice with details about the spill, which often include volumes, locations, affected area, and containment/ cleanup provisions (an increase of 13 percent since 2017). In four states the operator is also required to notify the landowner in the event of a spill. Twenty-three agencies regulate the remediation of spills including 15 that specify that the clean-up standards must reflect the material spilled, and 14 that have some measure of quantified cleanup standards (an increase of 29 percent since 2017). For example, Colorado's regulations specify the cleanup standards for organics and inorganics in soil and groundwater, including allowable concentrations for total petroleum hydrocarbons, benzene, toluene, ethyl benzene and xylene, PAHs, TDS, EC, pH, SAR, and various metals. Figure 4-24 shows some of the spill management requirements implemented by oil and gas agencies.

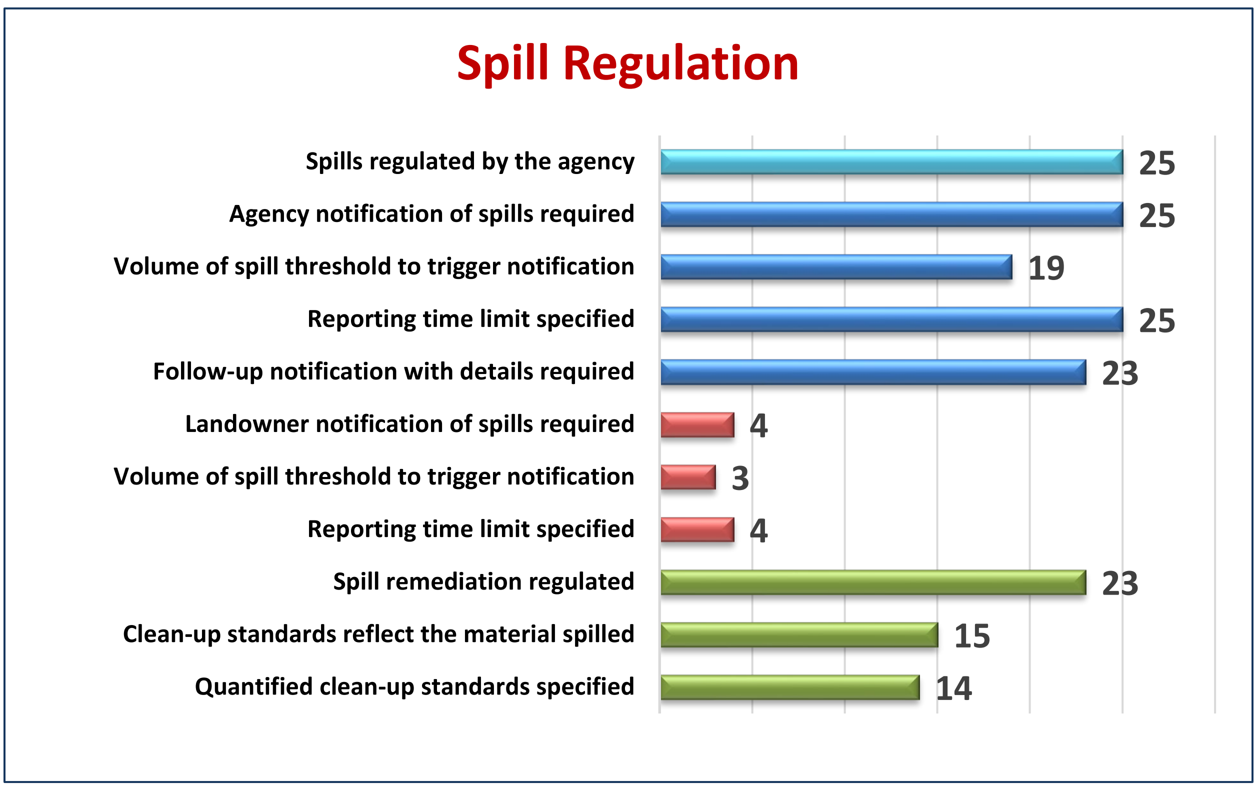

Figure 4-24

Chapter 5: State Programs

The implementation of regulations dictates their effectiveness. State programs utilize many tools to implement regulations including permitting processes, inspection protocols, enforcement procedures, staff training, data management, and others. In this chapter we discuss how state programs utilize tools within a regulatory framework to ensure that human health and the environment are protected.

State Programs: The Drivers of Effective Regulation

Regulation without implementation cannot achieve environmental protection. To gain a more complete understanding of the regulatory process one must consider the means by which regulatory language is translated into regulatory action. To provide this understanding the study profiles selected areas of state oil and gas regulatory programs, including staffing, budgets, inspections, and orphan sites programs, and the use of supplementary documents that fall outside the traditional bounds of notice-and-comment regulation. In addition, external processes used by regulatory agencies such as independent technical guidance, training programs, and program auditing programs are discussed below.

Regulations and Programs, the Regulatory Framework

While state regulations form the backbone of the regulatory framework, it is the state programs that provide the means for implementing regulatory requirements. Programs consist of many elements including staff, policies, procedures, guidance, equipment, and management. The proper application of these elements to regulatory needs is crucial to the goal of protecting the environment. In this context it is important to remember that not all situations and circumstances are the same from state to state. The needs of a program in one state may be substantially different than those in another state due to differences in geology, geography, hydrology, climate, land use and many other factors.

Critics of regulatory variability between states may assume that more regulation is always better and that differences between programs indicate flaws or inadequacies. Some studies have cited the variability between state programs as de facto evidence that some programs are better or worse than others at protecting the water resources. The fact that there are differences between state programs has also been used to call for national regulation of oil and gas activities like hydraulic fracturing. In fact, the variability between state programs is a natural outgrowth of the unique characteristics in each state as noted above.

From the public viewpoint it may appear reasonable to conclude that all state programs should implement the same operational requirements and that they should be the most technologically advanced. This is not necessarily true. The question of which regulations are best for a state is most effectively answered by each state's regulatory programs, given state regulators understanding of the unique circumstances that exist within their states. State regulatory programs have the necessary in-depth knowledge of regional and local conditions that provide the basis for the development of appropriate regulatory requirements.

General Structure of State Oil and Gas Programs

Although each state has a specific organization relative to its unique circumstances, most regulatory programs follow a general pattern or structure. Many oil and gas regulatory programs follow a structure similar to the following:

- Program oversight through a board or commission;
- Management staff that typically consists of a director or supervisor with at least one deputy or assistant director or supervisor;
- Section managers in areas such as permitting, UIC, field operations, enforcement and others;
- Technical staff that typically includes petroleum engineers and/ or geologists and in some cases oil and gas E&P technology experts, seismicity experts, site construction experts, compliance experts and others;
- Administrative staff that typically include office managers, information technology personnel, financial assurance reviewers and others; and
- Legal staff (or access to legal staff) that include attorneys, legal aides, hearings officers and others.

Role of Supplementary Documents in Regulation

A comprehensive understanding of a state's regulatory program includes a review of supplemental documents used by agencies to implement their programs. State agencies utilize a wide variety of guides, manuals, policies, and similar tools to complement and clarify their regulatory programs. These documents provide guidance often on a daily basis for agency employees and industry entities alike, helping all parties apply sometimes broad regulations to more discrete events, circumstances, and permit conditions. While this section does not provide a complete overview of the unique supplemental documents and tools at work in each state, it serves to acknowledge the existence of these additional materials and provide examples that illustrate their role in oil and gas regulation. *NOTE: The items listed below are presented in increasing order of formality.*

- **Field Rules:** These rules (sometimes called orders) are often specific to a particular oil and gas field, pool, zone, or other narrowed geologic location, supplementing more broadly applicable statutory and regulatory requirements. They allow regulatory agencies to incorporate geologic, engineering, and other types of unique data for a field into a more focused set of rules for operators in different regions of the state. These rules often relate to regulations that require local details and unique information such as well spacing, drilling, and completions operations or allowables. For example, North Dakota has a special field rule addressing proper spacing for the development of the Clarks Creek-Bakken Pool in McKenzie County, and California's Bellevue Field Rules require annular cement fill to the surface or at least 500 feet above the uppermost oil, gas, or anomalous pressure zones;

- **Policies, Notices, and Orders:** Policies, notices, and orders are, in many cases, official documents that can set forth the manner in which agencies expect operators to conduct their operations within the scope of the existing oil and gas rules. These documents may simply indicate how an agency intends to interpret and apply certain rules generally, or may bind specific parties directly. Often, these documents are used to address very specific or unique aspects of operations or to clarify certain rules that an agency has found to be particularly confusing or problematic. For example, Colorado has a policy specific to bradenhead monitoring during hydraulic fracturing treatments in the Greater Wattenberg Area. Indiana published a policy letter memorandum on coal seam protection clarifying requirements for new wells that also included a FAQ section. Sometimes, notices will be published to bring operator's attention to revisions in certain requirements and how those revisions apply in specific situations. For example, Arkansas published a notice to operators regarding revised casing requirements for wells drilled in specific counties. In Kansas, precedential orders may bind immediate parties facing a special circumstance while also creating precedent for future similar situations, one example being a particular application to establish special field rules for horizontal wells in the Mississippi formation. Michigan's State Supervisor of Oil and Gas has the authority to issue "Supervisor of Wells Orders" which serve as direct notices regarding requirements applicable to a particular situation that requires special attention. Supervisors Order #2-73, for example, sets forth casing and sealing requirements for certain wells drilled with rotary tools;

- **Forms:** Forms are perhaps the most common supplementary documents used by state agencies to implement regulations. Although rules will sometimes specify the information that must be contained in a report to the agency, they will more often simply require that an operator report information about their activities on a form "prescribed by the agency." The forms used to submit reports are usually developed by the agency and include such reports as Well Completion or Recompletion, Sundry Notices, Notices of Intent, Well Stimulation, Well Plugging and various other reports used to provide well and site specific information to the agency. Even where a rule specifically states what has to be reported to an agency, the forms used to submit the report may expand upon the rule language and include information not specifically listed in the rule. In some cases, the information about a particular activity may be contained on more than one form. For example, Well Completion or Recompletion reports usually contain information about the depth of the well, the construction specifications, testing and some well stimulation activity such as materials used. In addition, some well treatment reports may contain information about the pressures used in the treatment process, the specific chemicals that may have been used, the actual depths of each treatment interval and other information. As a result, these forms must be reviewed in tandem to gain an overall understanding of a well treatment. Although forms are not rules, the information contained on the form is typically mandatory. Failure to provide the information listed on a required reporting form is a violation of state rules and usually may result in enforcement action regardless of whether a state rule lists the particular information required by the report;

- **Guidance, Manuals, Instructions, and Handbooks:** These documents break down certain aspects of rules and regulations, most often related to requirements or conduct necessary for particular processes or operations. These supplements to a state's regulatory program assist entities in navigating certain aspects of their operations in a manner that satisfies all applicable regulations. In some instances, agencies will go through a public notice and comment period when they write or amend these documents. These materials address various aspects of field operations, and can provide an all-in-one resource for operators, bringing together relevant rules from various agencies in a state which regulate aspects of oil and gas operations. For example, Kentucky's principal secondary document is called an "Operator's Manual" and includes rules from multiple agencies, while Alaska publishes industry guidance bulletins that describe the conduct of specific operations, such as Bulletin No.10-02A, which specifically addresses mechanical integrity testing. New Mexico has an environmental handbook that contains the requirements for discharge plan approvals, groundwater contamination investigations, waste oil treating plants, below-grade tanks, and several other environmental topics.[44] Pennsylvania publishes various technical guidance documents that provide additional information to operators beyond the language of the rules regarding spills, well integrity, wastewater permitting, and other similar topics;

- **Best Management Practices (BMPs):** These documents describe practices in the oilfield that are recommended as the best available means of conducting a particular activity.

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[44] State of New Mexico, Oil Conservation Division, GUIDANCE DOCUMENTFOR GROUND WATER DISCHARGE PERMIT APPLICATIONSAT REFINERIES, NATURAL GAS PLANTS, WELL PAD TANK BATTERIES, GAS COMPRESSOR STATIONS, CRUDE OIL PUMP STATIONS, AND OIL AND GAS SERVICE COMPANIES (REVISED 9-2022), https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/GW-Discharge-Permit-Application-Guidance-Document-September-2022-1.pdf

They do not typically have the force of law, but rather serve as recommendations only. For example, Ohio has a best management practices document addressing oil and gas wellsite construction, while Oklahoma utilizes a document entitled "*Pollution Prevention at Exploration and Production Sites in Oklahoma—Best Management Practices for Prevention and Control of Erosion and Pollution*" to manage well site construction and operation; and[45]

- **Technical documents:** These documents are typically produced for industry as operational guides and standards. Organizations such as the API, ASTM, National Fire Prevention Association (NFPA) and others have processes for developing standards and guides that are designed to achieve professional consensus among experts from numerous fields and can be applied by regulators and operators. These documents are often referenced in regulatory language because they can provide a high degree of specificity and typically quantify what is considered "standard industry practice."

Staffing and Equipment

As noted above, oil and gas agencies are typically staffed by natural resource professionals including managers, geologists, engineers, administrators, and usually attorneys. In 10 of the 14 states responding to a 2017 GWPC survey, a geologist or engineer must review drilling permit applications. In some states, a college degree (Associates or Bachelors) or equivalent industry experience is required to qualify for a field inspector position. States provide specialized field equipment to inspectors for many purposes. For example, in 13 of the 14 states responding to the survey, field inspectors are equipped with laptop or equivalent electronic data capture equipment that allow them to see the inspection and enforcement history of a well or surface facility and to submit electronic inspection reports to a district or central office for review and follow-up. In 10 of the surveyed states, inspectors are also equipped with kits or meters to perform field tests of water quality. Further, all 14 surveyed states equip their field staff with GPS receivers that can be used to accurately locate a well, determine a tank battery or pit location and boundaries, and assist in the accurate identification of facilities. Finally, 11 of the surveyed states equip their field staff with smartphones to aid in communication with district and central offices and with other inspectors. District and central office staff are typically equipped with personal computers and have access to vehicles to conduct field site visits and attend public meetings and hearings. In addition to internal staff, most oil and gas agencies have access to other state resources including technical and field staff of other state environmental agencies and legal services of the State Attorney General's Office. For example, in some states it is the responsibility of the Attorney General to provide legal services for the collection of penalties issued by the oil and gas agency.

45 Oklahoma Corporation Commission, https://oklahoma.gov/occ/divisions/oil-gas/pollution-abatement-department/spills-pollution-response-pollution-prevention.html

In other states, an environmental agency may provide field services such as sampling and analysis, specialized equipment such as electromagnetic meters to measure soil conductivity and identify underground saltwater plumes, and technical expertise from staff chemists, biologists, toxicologists, and other technical staff. Although the GWPC did not undertake a survey in 2021similar to the 2017 survey, given the rapid expansion of electronics usage, internet access via Wide Area Networks (WANs), and cellular data transfer capabilities since 2017, it is very likely there would be several more states utilizing technologies such as smartphones, tablets, and laptop computers in the field.

Budgets

Budgets are based on several factors including legislative and executive priorities, funding source availability, and agency needs in areas such as staffing, equipment, technical support, and others. The amount of an agency's budget has an effect on many operational functions including permitting, administration, technology support, legal support, and field operations. For example, decreases in budgets can result in shifting priorities for field inspections from routine to more periodic or targeted inspections. This is a reality that each agency must address based on their own determinations as to how to apply the funds available in a manner that provides the greatest benefit at the lowest cost. Because agencies are funded using a variety of sources such as general funds, permit fees, severance taxes, injection fees and others, the size and stability of budgets can be affected by changes in the value of oil and gas, general state financial condition, downturns in oil and gas industry activity and other factors. Consequently, budgets are a primary factor with respect to an agency's ability to implement their oil and gas regulations because budgetary constraints can affect staff size, travel capability, equipment procurement and maintenance, software and hardware development and a number of other essential agency needs.

Inspections

Site inspections are one of the core functions of a regulatory program. They provide the on-site evaluations of operations that are essential to determine the effectiveness of the program. Without field inspections there would be no way to audit implementation of the regulations to determine whether or not they are providing the environmental protection intended. Field inspectors use many different methods for capturing the results of their inspections. For example, in 2017 seven states inspectors used either handwritten checklists and/or free form written notes. In nine of the surveyed states, inspections were captured electronically using computer designed forms that are part of a program that allows the inspector to transmit the inspection information to the agency's field or central office for incorporation into a database. As with the staffing and equipment section noted above, the GWPC did not conduct a survey of state agencies relative to inspections for this report. However, the number of states capturing field data electronically is likely to have increased significantly since 2017.

While the time it takes to conduct an inspection varies widely depending on the density and accessibility of wells, the criteria used to conduct inspections, and the experience of the inspector, many states have policies to inspect wells on a routine schedule. Increases in the current frequency of well inspections would tend to require additional staff. Therefore, it is critical for states to focus their existing inspection efforts where they will do the best. Using indicators such as prior enforcement history; proximity to drinking water sources; sensitive ecosystems, and urban areas; well types and ages; and types of activities such as plugging and well construction, agencies can inspect those facilities that pose the greatest risk of harm to the environment and human health. These prioritization/ assessment programs allow states to utilize their staff resources in a manner that is the most efficient and provides the greatest environmental benefit. For example, there are several potential criteria that can be used for prioritization such as:

- Environmentally Sensitive Areas;
- Source water recharge areas;
- Proximity to Urban Areas;
- Proximity to Surface Water;
- Age since last Inspection;
- Past Inspection Results (compliance); and
- Well Type.

There are several examples of specific inspection protocols that increase inspection efficiency and effectiveness:

- Nebraska uses a Geographic Information System (GIS) overlay of wellhead protection areas to design their well inspection program;
- Utah uses a Prioritization Module that will prioritize inspections using multiple factors;
- Colorado utilizes an inspection prioritization program based on well risk factors including well condition and location: and
- The Kansas Corporation Commission operates a system called KOLAR (Kansas Online Automated Reporting System), which includes aerial photos of wellsites, pits, and tanks to identify nearby water bodies and enhance site inspections. Kansas also utilizes a sensitive area designation in its inspection program.

Field inspectors receive training in many different ways including On-the-job (OJT), through formal education in engineering and geology programs at universities, outside training via technical training courses such as Hazardous Materials (HAZMAT) and specific field inspection training provided by a consortium of three universities (Colorado School of Mines, Penn State University, and The University of Texas at Austin). This consortium referred to as TOPCORP provides courses designed to prepare inspectors to meet the needs of inspector training certification .[46]

Data Management

The importance of having and managing good regulatory data cannot be overstated. Information lies at the heart of effective regulatory implementation. The regulatory agencies' ability to collect, store, extract, analyze, and accurately present data is essential to the protection of water resources.

By sharing and validating data, with regulatory field staff, regulated industries, and the public across agency jurisdictions, decision-makers can accurately assess trends in energy production, water quality, and supply. This information is essential to maintain the delicate balance between competing natural resources such as petroleum and water. Unfortunately, the fact remains that, although electronic conversion of paper records is continuing to progress nationwide, much environmental compliance monitoring data is still not available in electronic format. Even in agencies where automated data systems exist, vast filing systems of wholly paper-bound archives still provide the primary access to important legacy background data. Obstacles to converting these archives to electronic databases include lack of funding and overstretched personnel resources.

Wise natural resource management requires access to 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. Many states now manage large amounts of data through client-server database and cloud-based applications. In the past, the extensive variability in development tools used to create data management systems and differences in their form and function created many technical obstacles in sharing data between state agencies and the public. Overcoming the barriers created by early software programming and hardware choices has been difficult, with the result that large quantities of data were accessible by only a few people. However, efforts are being made to resolve this issue.

Because the internet has become the preferred method for accessing information and data, database development and implementation is increasingly reliant on web based programming to fulfill this need. Each of the 27 state oil and gas agencies in this study maintains a website where the public can access information about agency actions such as permitting, regulatory hearings, links to helpful documents, and in some cases direct access to agency electronic files through web-based interfaces and GIS mapping programs.

[46] TOP Energy Training Consortium, https://topenergytraining.com/topcorp/

To facilitate the evolution from paper-based forms submittal and manual processing to electronic submittal, scanning, processing, and web-based publication of technical data, the states have spent the past 30 years developing, continually improving, and incrementally rolling out GWPC's Risk Based Data Management System (RBDMS). This effort is accomplished within the constraints of agency workloads and program funding. Currently, there are 21 RBDMS Partner states (See Appendix 12, Map of RBDMs Partner States).

RBDMS has 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.

Another data management system developed by the GWPC can be used by agencies to process data related to earthquakes resulting from underground injection of fluid. The system, called Oklahoma Water Seismic Management (OWSM) tracks the location, strength, and depth of earthquakes and correlates them to the injection of fluid over time. The system greatly decreased the time it took to evaluate underground injection relative to earthquake activity. At present the system is used only in Oklahoma and Texas with Kansas in final review. However, other states have expressed an interest in using it.

One of the more notable developments in data management and public accessibility involves the reporting of hydraulic fracturing chemicals. In 2011, the GWPC and the IOGCC implemented a joint project designed to set up a nationwide, state-by-state data system capable of storing chemical disclosures and presenting them to the public on demand. This effort became known as FracFocus. The FracFocus system is an educational and disclosure presentation system designed to inform the public about the process of hydraulic fracturing and provide them with the means to see a report of the chemicals that were used on a particular hydraulic fracturing job. The FracFocus website includes information on hydraulic fracturing and how it works, groundwater protection, chemical use, regulations by state, and disclosure.[47] It also addresses frequent questions and includes a form for the public to pose questions. To date, more than 8,000 inquiries from the public have been addressed through this system and the website has received nearly 4 million visits. Although the system was initially designed to provide for voluntary submission of disclosures, as of January 2021 27 states required or allowed use of the FracFocus system to submit regulatory chemical disclosures, with more pending (See Appendix 11, Map of FracFocus Partner States).

[47] FracFocus website, GWPC and IOGCC, http://www.fracfocus.org

The FracFocus system contains more than 184,000 chemical disclosures submitted by over 1700 companies

As of this report, more than 184,000 disclosures had been submitted to the FracFocus system by over 1,700 companies. These disclosures can be found by the public using the *Find a Well* search form that allows them to search by different parameters including state, county, well name, operator, API number, job date, ingredient name, address, zip code, and Chemical Abstract Service (CAS) number. Disclosures are presented in the Adobe® portable document file (PDF) format. Additionally, the FracFocus site now allows users to download disclosure data in machine readable format (MS SQL Backup and CSV).

Information captured by FracFocus disclosures includes the location of the well by state, county, and coordinate location, the name of the oil and gas operator, the true vertical depth of the well, the volume of water or other fluid used as the base carrier fluid for the fracture job, and a list of the products, suppliers, ingredients, and their percentages by mass for each chemical used in the fracture job. For further details about the FracFocus program, see "Chemical Disclosure" in the *Well Treatment, Stimulation and Fracturing* chapter.

State agencies have historically developed, and operated oil and gas databases tailored to meet their day-to-day state regulatory needs. Federal databases are not designed to provide the operational functionality of state databases, but they can use data from state database systems to provide a national picture of oil and gas operations.

Other Regulatory Processes

Many states have additional processes for enhancing environmental protection of water resources. One of the most common is "orphan well" programs utilized by many states to plug inappropriately abandoned wells when the well owners cannot be found or are unable to pay for proper abandonment. These programs are designed to address abandoned oil and gas related wells through a variety of processes including state plugging, alternate operator plugging, well adoption and others. The agencies with orphan well plugging programs use funds dedicated specifically to an orphan well fund to plug wells. Some states such as California and Indiana provide incentives for operators to "adopt" orphan wells for the purposes of putting them back into operation. Such allowances lessen the number of orphan wells and allow states to stretch their orphan well dollars further, while also putting formerly abandoned wells back into operation.

To facilitate the plugging of orphan wells, the Bipartisan Infrastructure Law (Infrastructure Investment and Jobs Act, IIJA, H.R. 3684) became law on November 15, 2021. A part of this law provides $4.7 billion dollars in funding to plug abandoned orphan wells on State, Federal and Tribal lands through the U.S. Department of the Interior (DOI) over a 10-year period. On August 25, 2022, the DOI announced it had approved $560 million dollars in Initial Grants to 24 states. DOI is administrating the funds and developing guidance documents for grant recipients on management, data submission, and methane mitigation. The DOI is supported in the effort with consultation and technical support from the EPA and the US DOE. In addition, the IIJA provides funds to the IOGCC to consult with DOI and support states in their grant applications and grant management. *Note, as of October 2022 Texas was actively plugging wells with the funds and many other states had wells under contract to be plugged.*

For States there are 3 types of Grants listed in the Legislation. Each has various deadlines and requirements to meet. Most of the requirements are very similar and include:

- **Initial Grants: First Year Grants**: Required if state expects to apply for Performance Grant. At end of one year must return unobligated funds. Requires results report after 15 months;
- **Formula Grants:** Funding is allocated based on formula set up by DOI. Funded for 5 years. Unobligated funds to be returned; and
- **Performance Grants:** Annual grants running for ten years. Includes grant options for Regulatory Improvement and Matching Grant Funds. Specifies that states will update their plugging rules/regulations.

To support the program GWPC is has developed an orphan well data management system with two modules in pilot use:

- **Module 1:** Which will help states devise a prioritization schedule for plugging orphan wells; and
- **Module 2:** Which will allow states to manage well plugging operations including contracting and required reporting to the Department of Interior.

Enforcement and compliance programs are key regulatory activities designed to assure the regulations are followed. With respect to enforcement most, if not all, states typically utilize a progressive enforcement system where actions are taken in a stepped process that advances from less formal to more formal notifications and, sometimes, sanctions. Actions such as informal notices and warnings, official notices and administrative orders, hearings, permit suspensions and revocations and, in some cases, judicial proceedings are all part of a toolkit many agencies can apply to resolve non-compliance. As of the 2017 report, eleven of the states reviewed had civil penalty authority; which is a valuable compliance tool. Based on recommendations made in Class II UIC Program Peer Reviews conducted by GWPC since 2017, it is likely other states may also seek civil penalty authority to increase compliance. Inspectors, field supervisors and agency enforcement managers work in concert to resolve instances of non-compliance and, where necessary, take administrative actions to return operations to a compliant state.

Another aspect of state programs that is important to consider is the ability of agencies to witness critical field operations such as well casing and cementing, mechanical integrity testing, and well plugging. For example, eight states specifically require the witnessing of well plugging, while six allow the submission of cement tickets in place of witnessing. The witnessing of well plugging provides the agency with additional assurance that the materials and methods used to plug a well are consistent with approved plugging plans and state requirements.

Other special regulatory program elements utilized in various states include specific requirements for drilling in high-density residential areas, limits on the number of idle/ temporarily abandoned wells, deployment of environmental specialists in field offices, availability of all well files including well logs, oil and gas orders and others via the internet, and pre-drill site inspections. These programs are designed to enhance regulatory management and improve public transparency.

In the past several years, a focus of regulatory concern has arisen out of the increase in seismic activity related to oil and gas operations. Seismicity induced by underground injection, hydraulic fracturing and even well completion techniques has resulted in a regulatory response in a number of states. To assist in this effort the GWPC and IOGCC developed an "Induced Seismicity Primer" in late 2015 and updated it in 2017 and 2021.[48] This primer provides regulators with information they can use to assist them in preparing a plan of action to address induced seismicity through both pro-active and responsive action steps.

External Processes: Support for State Programs

There are a number of external processes that provide assistance to state programs. For example, the GWPC holds at least two annual conferences to conduct staff training for and facilitate technology transfer to and between state regulatory agencies. Additionally, organizations such as the IOGCC conduct routine meetings where state officials can interact and coordinate responses on important regulatory issues. GWPC and IOGCC have provided several types of support to state regulatory programs using a number of specific tools such as those descri
The Exchange is a joint effort developed by GWPC and IOGCC members to help states institutionalize a process of continuous improvement of oil and gas regulatory programs.

This partnership has offered the following services:

Information and Education Services

[48] Induced Seismicity Guide: https://www.gwpc.org/wp-content/uploads/2022/12/FINAL_Induced_Seismicity_2021_Guide_33021.pdf

Examples of information and education service include efforts such as a multi-state survey of field inspector salaries, technical workshops, or information gathered and exchanged between states experiencing common issues.

Assistance with Rule Updates

Assistance has included both peer reviews and peer consultations on particular regulatory topics, such as well integrity regulations or storage pit regulations. Peer reviews are based on lists of "regulatory elements," developed for particular subjects. Peer consultations draw on the expertise of regulatory peers in multiple states, but are not necessarily based on formally adopted lists of regulatory elements. In addition to peer reviews and consultations, This collaboration has, if requested, advised, or assisted states on multi-stakeholder reviews of one or more focused regulatory areas. For example, at the request of the Idaho Department of Lands, the partnership conducted a peer review of select elements of the Idaho Oil and Gas program in 2016 and issued a report.[49]

Convening Services

The GWPC and IOGCC have convened forums for state policy and technical staff to share the ways they do business, review internal operations, and open up opportunities for extrapolating effective practices from one state to anotherand has also sponsored multi-stakeholder forums for state policy and technical staff to meet with other interested stakeholders to discuss issues of mutual interest. Some examples include stray gas induced seismicity events, produced water, use of drones, or improving data systems would be examples of such services.

Activities

Inspector Certification Course

The National Inspector Certification Program, instituted in 2000 by the IOGCC establishes national standards for state regulatory agencies to certify personnel responsible for inspecting oil and gas wells. Due to inherent differences in geology, site characteristics, weather, operations, organizational structure, and stage of development of each state, the certification program includes mandatory criteria applicable to all states, with an option for testing on state specific standards.

[49] "Idaho Department of Lands Peer Assessment Report 2017", January 30,2017, 11 pp. https://www.gwpc.org/wp-content/uploads/2022/12/IDAHO_AssessmentReport_FINAL_2017_01_30_0.pdf

Some of the topics in the certification training program include Oilfield Terminology, Topographic Mapping, Seismicity, Well and Pit Siting Criteria, Drilling Procedures, Well Control, Cementing Procedures, Well Completion Procedures, Horizontal & Directional Drilling, Production, Underground Injection, H2S, NORM, Pollution Prevention, Well Plugging & Required Performances Objectives and Communication & Mediation. As of this report, over 225 inspectors from 12 states have participated in the certification program. [50]

Figure 5-1 Field inspection of wellsite in Geauga County, Ohio- Source, Ohio DOGRM

Other Exchange Activities

At the request of the Colorado Oil and Gas Conservation Commission (COGCC), oil and gas regulators from Alabama, Alaska, and Arkansas reviewed Colorado's regulations relating to idle wells. In Colorado, idle wells represent any well that is shut-in, temporarily abandoned, suspended, or idle for any other reason and not properly plugged and abandoned to the requirements of the state. The assessment found that Colorado requirements for idle wells are comparable to those of other oil and gas producing states and provide reasonable approaches to address the concern of establishing regulatory methods to keep useful wells and protect the state from the liability of useless and orphaned wells.

In November 2019 the IOGCC and GWPC conducted a training course for state regulatory officials on the use of drone technology. This course, which was held in Oklahoma city covered topics such as "what drones are, different types of equipment, drones that are best for your particular purposes/issues, license requirements, training programs, legal issues related to relationships with landowners, liability, case studies from state programs, and development of implementation plans."[51]

In 2017 the Virginia Department of Mines, Minerals and Energy (DMME) requested an examination of the following regulatory areas of its program:

• The existing laws and regulations that govern exploration and production of oil and gas resources in the eastern half of the Commonwealth (Commonly referred to as the Tidewater region); and
• Whether DMME should adopt regulations governing Naturally Occurring Radioactive Material (NORM) and whether those regulations should apply statewide or only in specific regions.

[50] IOGCC, 2017

[51] Drone Training Course, https://www.stateoilandgasregulatoryexchange.com/drone

.[52]

Regulatory Coordination: Eliminating Gaps in Environmental Protection, Human Health, and Safety

Regulatory coordination is often based on individual interagency relationships that vary from state to state. Formal regulatory coordination is a valuable element of regulatory management. Inasmuch as regulation of all elements of oil and gas E&P are typically not exclusive to a single agency, it is critical to assure that all the "moving regulatory parts" work in concert to close gaps that could result in inefficient and ineffective regulation and potential environmental harm. Although there are different ways to accomplish this, one of the most effective is the development of Memorandums of Agreement or Understanding (MOAs and MOUs) between agencies. These documents specify the jurisdictional nexus between agencies, define agency responsibilities and authorities, and detail the communication plans, activities, and personnel assignments unique to each agency. Memorializing the responsibilities of each agency in a formal document provides clear direction to agency management and staff as to their individual role in the regulation of a particular operation or event. It also leads to better general communication between agency staffs and develops professional relationships that are useful in any multi-agency effort. Finally, having formal agreements between agencies allows each agency to concentrate its efforts and resources where they have clear authority while avoiding "turf" battles that may require management intervention and tend to result in less effective regulatory implementation. A good example of the use of this type of document for regulatory coordination is the MOU developed between the Railroad Commission of Texas (TRRC) Oil and the Texas Commission on Environmental Quality (TCEQ) relative to the intersections of agency jurisdiction (See Appendix 8). However, MOAs and MOUs are not limited to state agencies. These agreements are also useful between state and local agencies and state and federal agencies. For example, in the UIC program each primacy state has an MOA with the U.S. EPA that describes the jurisdictional responsibilities and requirements placed on each agency.

In addition to pre-arranged agreements, state agencies also participate in event driven coordination processes. During major events, agencies will sometimes use existing management structures such as the Incident Command System (ICS) to respond. According to the Federal Emergency Management Agency (FEMA), ICS is "*a management system designed to enable effective and efficient domestic incident management by integrating a combination of facilities, equipment, personnel, procedures, and communications operating within a common organizational structure.*[53] *ICS is normally structured to facilitate activities in five major*

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[52] Virginia Peer Assessment, https://www.stateoilandgasregulatoryexchange.com/_files/ugd/d3e01e_31af3b42824b40e68ca359f90d738d85.pdf
[53] https://www.fema.gov/incident-command-system-resources

functional areas: command, operations, planning, logistics, Intelligence & Investigations, finance and administration. It is a fundamental form of management, with the purpose of enabling incident managers to identify the key concerns associated with the incident often under urgent conditions without sacrificing attention to any component of the command system." In ICS all activities related to the incident are coordinated through a command structure that involves all of the agencies and entities involved in the event. This is accomplished using an organizational structure that is designed around the five major functional areas described by FEMA and shown in Figure 5-2.

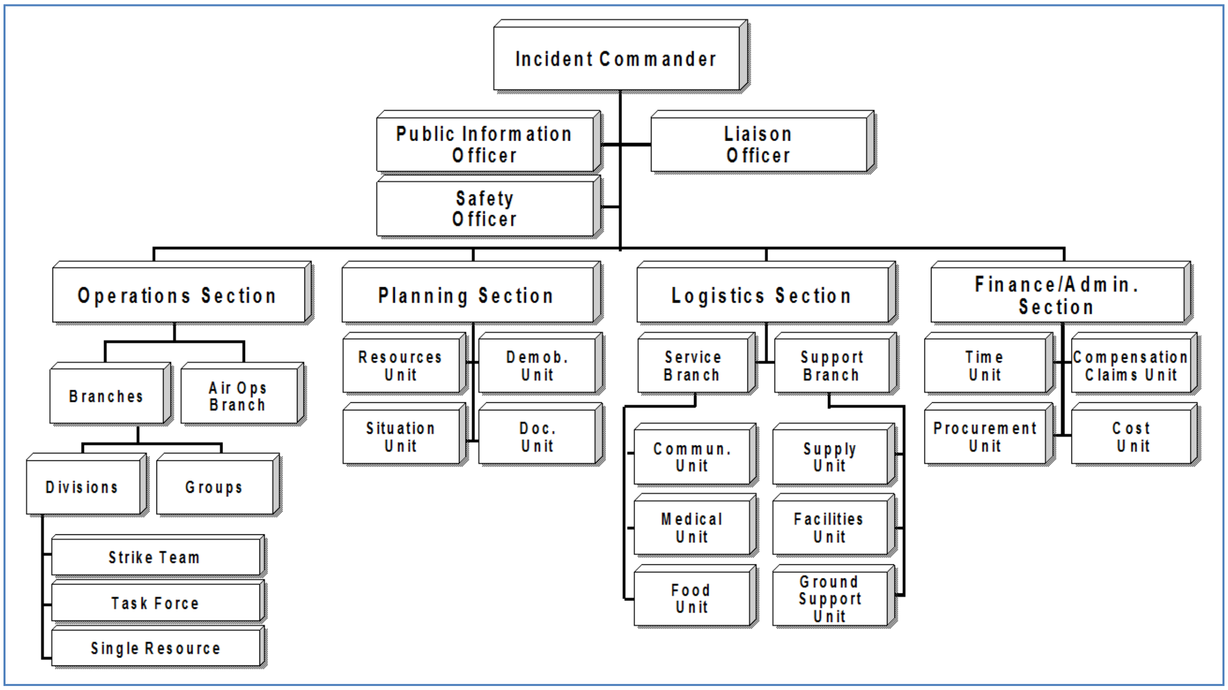

Figure 5-2 Structure of the Incident Command System Source: FEMA

One example of a situation in which ICS might be beneficial would be during a major oil spill. A spill might involve not only the state oil and gas agency and state environmental agency, but it could potentially involve local fire departments, health agencies, public water suppliers and others. Where multiple regulatory authorities are involved, the ability to effectively respond often times requires a coordinated approach with a clear chain of command, directed activities, public communication, financial management and other elements. The ICS process allows for such a response without the confusion, jurisdictional and command disagreements, uncoordinated communication, and ineffective operations that might result if each entity implemented its own response plan.

There are also individual state systems that coordinate the actions of agencies during an emergency. A good example of this type of system is the Ohio Division of Oil and Gas, Emergency Operations and Response section that was launched in 2015. This team is specially trained and focused on oil and gas emergencies and is able and ready to respond 24 hours a day, 7 days a week. A vital part of their mission is to work with local first responders so that they too can be prepared and safely respond to any oil and gas incident.

Coordinated regulation results in a better outcome for public health and the environment. It also results in cost and time savings. Prioritizing coordination as an element within the regulatory process is a "value added" activity that is critical to the implementation of a regulatory program that is responsive to public needs and fulfills an agency's regulatory responsibility.

Chapter 6: Current Key Messages and Considerations

This chapter of the report contains the key messages and suggested considerations related to some of the regulatory elements evaluated for this report and shown in Appendix 5. It is important to recognize that not all elements or considerations necessarily apply to all states or situations. Taking into account unique geology, geography, land use, climate and many other factors in each state is critical in determining whether or not a consideration would be of value to a state regulatory program. It is the province of each state oil and gas regulatory program, where the experience, training, expertise, and knowledge of states individual circumstances are well known, to determine if applying a specific consideration would be beneficial.

Key Message 1: Rules

The following 28 regulatory considerations are inspired by the results of this year's survey and represent, in GWPC's opinion, worthy rulemaking topics to address identified risks. As noted above, not all of these considerations are universally applicable, but they are presented as an aid for state regulators considering revisions to their programs.

Permitting

1(a): For states where topography, weather patterns or other factors pose challenges for well pad construction, rules that mitigate those issues.

Hydraulic Fracturing

1(b): Mechanical Integrity Testing requirements prior to well stimulation;
1(c): Monitoring and reporting requirements during well stimulation, and suspension of well stimulation when mechanical or formation integrity is compromised;
1(d): Analysis of confining zone(s) and "Area of Review"-style analysis of near wellbore geology to mitigate risk of conduits transmitting hydraulic fracturing fluids;

1(e):Defining the meaning of simultaneous operations (SimOPS) relative to hydraulic fracturing. *NOTE: Although listed under hydraulic fracturing, SimOPS is also relevant to other field activities; and*
1(f):Reporting volumes of water used by type (e.g., Produced water, groundwater, fresh water etc…).

Well Integrity

1(g): Comprehensive well integrity testing during construction, especially Formation Integrity Testing (or "shoe" testing) prior to drill out;
1(h): Centralization standards for production/long string;
1(i):Providing standards for reconditioned casing;
1(j): Specifying mix-water quality standards and requirements for free water content in cement;
1(k):Assuring cement is mixed, and pumped at a rate, to maintain consistent density;
1(l):Reporting of "kicks" during drilling to ensure well control oversight and to establish a better understanding of potential over-pressurized zones;
1(m):Standards for annular space minimums between casing strings and between strings and formation.

Temporary Abandonment

1(n): Monitoring of wells in TA status to ensure they maintain mechanical integrity; and
1(o):Establishing a maximum time duration within which a well may remain in TA status.

Production Operations

1(p):Bradenhead monitoring requirements to facilitate lifetime well integrity management; and
1(q):Requirements for operator inspections of piping, valves, flow lines and other appurtenances during operations.

Storage in Pits

1(r): Requirements should address siting, design, construction, operations, and closure of pits;
1(s): Competency standards for liners;
1(t): Inspections prior to use and during operations; and
1(u): Leak detection requirements.

Storage in Tanks

1(v): Requirements should address siting, design, construction, operations, testing, and closure of tanks; and
1(w): Tank material should be compatible with stored fluids.

Well Plugging

1(x): Cement placement across all protected water zones;
1(y)Witnessing of well plugging operations by agency representatives; and
1(z)Tagging of plugs where needed to assure proper placement.

Transportation of Produced Water by Truck or Pipeline for Disposal

1(aa): Permitting or licensing of produced water transporters and the recording of produced water volumes transported off-site; and
1(bb): Tracking and reporting of final disposition.

Produced Water Reuse for Oil and Gas E&P

1(cc):Chemical characterization and management of side streams such as treatment residuals;
1(dd):Regulation of use of produced water for uses in the oilfield other than well stimulation; and
1(ee):Siting, design, construction, operations, and closure standards for produced water pipelines.

Exempt Waste Disposition

1(ff):Manifests for off-site disposal where appropriate.

Spill Response

1(gg):Clean-up standards should be established that are quantitative and relative to the characteristics of the material spilled and the media impacted; and
1(hh): Follow up notification details to improve performance.

Key Message 2: Emerging Issues

The following eight "emerging issues" are topics the GWPC considers to be active, relatively novel (or present new aspects to old problems), approachable by many potential regulatory responses, and likely to come to regulators' attention in the next several years if they have not already. Again, not all of these issues will surface in every state, but will likely be consequential where and when they do.

2(a): Wellpad Construction

Modern oil and gas wells, especially hydraulically fractured horizontal wells, are situated on pads several acres in size. These pads may contain multiple wells, water storage infrastructure like pits and tanks, separator equipment, and hydrocarbon storage vessels. They are extensively used during hydraulic fracturing operations, when dozens of trucks may be entering and leaving the site. Well pads must be able to manage considerable stresses from heavy loads (including the drill rig) and prevent flow of fluids offsite, especially into protected waters.

In recent years, after a string of high-profile well pad failures evolving severe erosion with pollution discharges into waterways, states with challenging climate and topography began developing rules for well pad construction. Ohio in particular adopted rules concerning features of the well pad, emergency release plans, sediment and erosion plans, and a geotechnical report. The rule notably requires engineer certification for the well pad's construction.

Not all states require detailed well pad construction, but states that have had contamination incidents related to well pads may consider investigating a regulatory solution.

2(b): Aging and abandoned infrastructure, including testing protocols for temporarily abandoned wells.

The United States has had extensive oil and gas development for over 150 years. While new wells are drilled every day, a substantial proportion of production is from older wells, sometimes in continuous operation for decades. There are two potential problem areas with respect to environmental protection – aging infrastructure is more prone to failure than newer infrastructure, and wells set on "idle" status that are not properly monitored are more prone to failure than operating wells.

With respect to aging infrastructure, states address (or can address) increased risks through inspection prioritization, financial assurance requirements, and lifetime equipment monitoring and repair protocols. On inspections, states can give added weight to older infrastructure as part of their prioritization of field visits. On financial assurance, states can require operators to provide bonds or other instruments to allow for closure and/or remediation of aging infrastructure so as to defray public clean-up costs, and to apply such requirements to ownership transfers as well as new developments. On lifetime operations protocols, states can require management plans that show how operators plan to regularly test equipment and make repairs as necessary for wells, regular annular pressure monitoring is a common component of such plans.

As for idle wells, the reason for heightened concern is that wells not under production can degrade without the signs that are readily apparent in production wells not just annular pressure readings, but also changes in production rates. Most states' granting temporary abandonment status to wells come with requirements that those wells be periodically monitored, ranging from fluid level checks to mechanical integrity tests. States might consider whether their monitoring requirements are optimized for regulatory confidence in the results and protection against intrusion of contaminants into protected water. Further, states may want to consider a duration limitation for wells in TA status to assure that, as these wells age, they do not become an environmental liability.

2(c): Modular, Site-Assembled Containment Structures.

As more water is stored on the surface for longer periods, operators are looking at new storage solutions beyond pits and traditional tanks. Modular, site assembled containment structures (modular tanks) are becoming increasingly popular. These structures consist of an outer steel containment wall (typically round but may be rectangular) comprised of sections that are attached to each other in the field (usually by bolts) with a geosynthetic membrane draped inside. These above-ground containment structures are open on top.

These containment structures are basically a mix of above-ground tank and above ground impoundment with advantages and disadvantages of both. The advantages of modular tanks include the ability for them to be assembled and disassembled relatively quickly. A disadvantage of the structures is the inability to install an active leak detection system beneath the geosynthetic liner. Leak detection must depend on visual inspections of the outer steel walls looking for evidence of seepage and observations of unanticipated drop in fluid level. A leak in the liner that results in downward fluid movement may go unnoticed for a significant period of time.

Related to storage in a tank system, secondary containment is critical to keep a leak from becoming a more wide-spread release. A failure of a modular tank will most likely result in an immediate, and potentially catastrophic, loss of the entire stored fluid. Such a rapid release of fluid could compromise a secondary containment structure or potentially impact a nearby modular tank resulting in its failure. Therefore, secondary containment design (including materials, construction methods, and volume) are important design considerations and may be different than secondary containment for a typical above ground tank. Proper spacing between modular tanks is also an important consideration to be addressed.

2(d): Produced Water Pipelines

Using pipelines to transport water over shorter distances may be advantageous over the utilization of trucks because it can be more cost efficient and offers the advantage of reducing truck traffic. Additionally, more operators are now relying more heavily on centralized produced water management operations and the use of Midstream water management entities which will typically entail both permanent (usually buried) and temporary (usually laid above-grade) pipelines to transport produced water to and from these facilities.

Although pipelines are an efficient mode of transport for fluids, they present increased risks, including those related to leaks and spills. Pipelines (both permanent and temporary) must be properly designed, constructed, and operated. This includes on-going inspection and maintenance, and ultimately decommissioning when removed from service.

As noted in the GWPC's report *Produced Water: Regulations, Current Practices, and Research Needs,* "Designing a permanent pipeline infrastructure must take into account physical and operating conditions including normal operating pressures and flows, pipeline material, pump station spacing, and control and isolation valves. Special considerations must be given to rights of way, the crossing of roads, railroad tracks, water bodies, and environmentally sensitive areas which may require a permit. Equally important is construction oversight to ensure construction meets design specifications and addresses any required field modifications during construction. Once the pipelines are installed, monitoring of operating conditions incorporating leak detection and routine inspections is important." Monitoring operations (whether visually or via remote sensing) can identify any leak of spill quickly and allow for appropriate action to be taken. Routine inspections are important to identify and address maintenance and repair issues. Once a temporary line is no longer needed, proper removal, including the emptying and purging of the pipeline, must be instituted. For permanent installations, formal decommissioning operation should be implemented.

2(e): Management of Residual Wastes from Produced Water Treatment.

As the 2020 report "U.S. Produced Water Volumes and Management Practices in 2017" notes, the vast majority of produced water is currently being disposed of by injection into disposal wells (91.5%)[54]. Increasingly, however, this fluid is being recycled back into well completion operations such as drilling and hydraulic fracturing. Reuse for hydraulic fracturing may require some level of treatment. Other management options such as surface discharge are also being considered. However, depending upon specific requirements, surface discharge would require robust treatment. Treatment operations, regardless of how basic or robust, produce a waste which must be managed and disposed of properly.

It is important that knowledge gaps, pertaining to the constituents removed by produced water treatment; which may subsequently end up in the solid waste stream and are typically more concentrated, are recognized, and efforts are made to address these gaps to both inform leading management practices and appropriate regulatory programs. Under the Resources Conservation and Recovery Act (RCRA), upstream oil and gas waste are generally exempted from the hazardous waste portion of the Act (Subtitle C) and managed under the non-hazardous waste portion (Subtitle D). However, as alternate management options requiring treatment are considered, it is important to be aware of any limits that may come into play with the RCRA Subtitle C exclusion which could significantly impact the methods and means of the management of residual waste. Regardless, to date, the status of residual wastes from produced water treatment with respect to the RCRA requirements does not appear to have been evaluated in any meaningful way.

2(f): Annular Pressure Management and Technology.

Annular pressure monitoring is the simplest, cheapest, and most common way to evaluate well integrity during completion and production. While such monitoring is a regular industry practice,

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54 Veil, John, U.S. Produced Water Volumes and Management Practices in 2017, GWPC, February 2020, 137 pp., https://www.gwpc.org/wp-content/uploads/2020/02/pw_report_2017___final.pdf

there are few regulations concerning frequency, response to unusual readings, and reporting requirements.

There are several new developments that may prompt regulators to consider adding requirements along these lines.

First, the API's RP 90-2, published in April 2016, provides considerable detail on annular pressure monitoring, and would likely be of help to states looking for formal parameters for a lifetime well integrity monitoring program.

Second, the cost of remote monitoring systems like SCADA is falling while the availability of wireless data connectivity is increasing. Such systems can send real-time well integrity data to operators, thus reducing well downtime and the duration of problems when they occur. Use of these systems is likely to increase, creating opportunities for regulatory engagement.

Finally, the sensor revolution is enabling advancements in annular pressure monitoring and other real-time monitoring technologies, both at the surface and the subsurface. Though large-scale deployment may be some time off, this is an area worthy of regulatory attention.

2(g): Alternative Management Strategies for Produced Water.

Across the country, dialogue continues regarding new and emerging issues associated with the management of produced water. Several factors, including drought conditions and limitations on disposal wells, have ramped up interest in alternative management strategies for this waste stream, including increased recycling in the oilfield, disposal via surface discharge, and beneficial reuse in other industries like agriculture.

GWPC is in the process of launching a project to investigate with more depth the unique issues surrounding produced water management. While new strategies for produced water management that divert this waste stream from underground injection for disposal to alternative uses both in and outside the oilfield provide the potential for positive, win-win scenarios in the future there is more to be learned and hurdles to overcome with respect to the science, technology, economics, and regulatory details of these emerging strategies.

A number of states have looked more closely at this issue since the time of the 2017 report. In Oklahoma, for example, the governor established a Produced Water Working Group (PWWG) to investigate and evaluate alternatives to underground disposal. The year-long working group effort, and the study report, in its draft stages as of the publication of this document, reviewed the economics associated with a number of alternatives. The draft report encourages continued investigation into the near-term feasibility of alternative disposal options (like evaporation) and technical and regulatory advancements that support expansion of in-field recycling by the oil and gas industry. These items were determined to be the 'low hanging fruit' for recycling options in the near-term but there are a number of areas where the practice could be optimized. As mentioned in the 2014 emerging issues section, in-field recycling of produced water will likely require advancements in treatment, storage, and transportation technologies to remove constituents of concern for use in operations and allow for the storage and movement of larger volumes of produced water at the surface in new ways. It will be important to identify and seek to minimize any new risks that may arise from spills and leaks of produced water as well as disposal of solids from treatment. Gathering more data and information on the volumes and current disposal practices in the field today may support more advanced and effective water management and recycling operations in the future.

Other alternatives for produced water management that intentionally release fluids outside of the oilfield require much more careful consideration due to new and less understood exposure pathways. The PWWG report found that alternatives such as reuse for other industries, discharge to surface waters, etc. would require advanced treatment technologies that are not currently economical. However, beyond the economic hurdles pointed out in the PWWG report, there are significant unknowns with respect to the chemical and toxicological character of produced water that raise questions about the environmental and human health risks associated with alternative reuse options, and make regulatory decision-making regarding the limits and permits that might be involved in such new operations complex.

Another example of produced water management progress is in New Mexico where New Mexico State University (NMSU), in collaboration with the New Mexico Environment Department (NMED), hosts the New Mexico Produced Water Research Consortium (Consortium). The Consortium is a trans-disciplinary public-private partnership comprised of academia, state and federal agencies, national laboratories, and the private sector. The Consortium focuses on conducting scientifically based research to support and foster regional sustainability.

A seminal work related to produced water is the 2019 GWPC report entitled "*Produced Water: Regulations, Current Practices, and Research Needs.*"[55] This report consists of three modules:

Module 1: Current Legal, Regulatory, and Operational Frameworks of Produced Water Management. This module focuses on the multifaceted regulation of produced water, including long established federal laws and programs as well as areas where additional regulatory clarity may be needed to further advance the beneficial use or reuse of produced water. It also discusses the legal and operational aspects of produced water reuse such as ownership, water rights, liability, and standard practices. These topics define the framework under which produced water

55 Ground Water Protection Council, "Produced Water: Regulations, Current Practices, and Research Needs", https://www.gwpc.org/wp-content/uploads/2019/06/Produced_Water_Full_Report___Digital_Use.pdf

reuse may be accomplished and the challenges limiting its current implementation as a water source.

Module 2: Produced Water Reuse in Unconventional Oil and Gas Operations. This module presents information on how produced water is used within oil and gas operations, with a focus on unconventional operations. Through literature reviews, interviews with oil and gas companies, and data requests, information has been gathered on the current state of oil and gas operational reuse of produced water and on future potential reuse options and dynamics.

Module 3: Produced Water Reuse and Research Needs Outside Oil and Gas Operations. The most forward-looking part of this report, this module looks at current and needed research to properly, and safely, use produced water in applications outside oil and gas operations. It also discusses the range of reuse options currently available along with potential reuse options that may one day become practical.

2(h):Water Use and Source

Policymakers and the public are increasingly attuned to water use and water disposition, especially as it relates to oil and gas development. Recent severe droughts in the central and western portions of the United States have highlighted the need to carefully manage competing demands on water resources. In response, some oil and gas agencies have been exploring how to better track the oil and gas water lifecycle with a focus on water source and the type of water used for operations like drilling and completion.

States are considering a variety of reporting formats to track and express this information. Many states collect some water use data via completion reports and FracFocus, with varying degrees of specificity. Water type has proven difficult to track because different states tend to have different definitions surrounding water quality (fresh, brackish, saline, etc.).

Given the intense interest in knowing both where water used for oil and gas development came from and its quality, it is likely that states will increase the specificity of their water use reporting beyond quantity in the near future, if they are not already doing so. As of this report's publication, GWPC's RBDMS is developing modules to help facilitate more sophisticated water use data acquisition, tracking, and reporting. Further, the GWPC is revising the FracFocus system to provide for the voluntary reporting of water sourcing in hydraulic fracturing operations. These revisions will allow for better tracking of the volumes of water used in hydraulic fracturing by source including surface water, groundwater, and produced water.

Key Message 3: Regulatory Programs

The following are regulatory program functions the GWPC believes are worthy of additional discussion.

3(a): Regulatory Coordination

As described in Chapter 5, state oil and gas agencies often pursue Memoranda of Agreement or Understanding (MOAs/MOUs) with partner agencies within their states and with the federal government. State/federal relations are managed in a variety of ways, including through state governmental associations like the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission.

These associations are very effective at bringing together state and federal agencies. But there is always room to improve these relationships, especially as regulatory frameworks evolve. For example, the Pipeline and Hazardous Materials Safety Administration (PHMSA) launched a regulatory program for underground natural gas storage in 2017, a program that had been primarily regulated by states. Developing formal MOAs/MOUs, either between individual states and PHMSA, or between GWPC or IOGCC and PHMSA, will help ensure a smooth transition to the new regulatory oversight regime.

3(b):Data Management

States have made significant strides with RBDMS over recent years. For example, California's adoption of RBDMS is precipitating a major upgrade that will bring RBDMS into the "cloud," making it more accessible to field staff and facilitating software updates. This upgrade to RBDMS was adopted and customized by North Dakota. Currently, Texas is in the process of adopting RBDMS, which will expand on features to the program such as facilities and waste hauling, operator licensing, and software as a service; which may make the Cloud version of RBDMS more readily adoptable by other states.

As a general matter, states should think about how to use their vast troves of data to reduce environmental risk , whether that is through programmatic Area of Reviews, inspection prioritization, or other programmatic areas that can be enhanced by data. While quality of the input data is key (enhanced by a recent trend toward electronic form submission), modern data analytics can provide significant insights to regulators to help optimize their programs. Most oil and gas agencies will not have data scientists on staff, but might consider partnerships with state university researchers to help explore the agencies data resources.

The GWPC is developing new tools and partnerships to increase transparency and accessibility of oil, gas, and water data. For example, WellFinder is a free mobile application (iOS & Android) that is available for use by anyone who chooses to download the application. It allows users to explore oil and gas wells in multiple participating states across the nation. Users can interact with the well information on an interactive map or through a data-centric view. WellFinder includes normalized values representing well name, status, type, and location information. This data comes directly from state regulatory programs. Links to state agency websites allow the user to see additional information about individual wells. Users of the application include agency staff, emergency response teams, and the general public. As of 2017 the total number of states using WellFinder was eight. However, as of this report, use of WellFinder has expanded to include wells and well data from additional states including Ohio, Louisiana, Illinois, and Indiana. The new additions bring the total number of states who currently supply data and participate in the app to 20. Additional states are in development and some of these should be active soon. WellFinder is also currently undergoing an upgrade designed to make it more user and state participation friendly and expand capabilities such as adding searches by well type and providing cross state boundary mapping via a website. The transparency provided by WellFinder increases trust, makes it easier for oilfield professionals to do their jobs, and makes it easier for the agency to learn about potential problems in the field. States not already engaged with WellFinder should consider participation.

Another example is GWPCs recent development of the WaterSTAR program. This program can be used to track water data including laboratory analyses through a user friendly interface that includes GIS, and data submission and validation capability. The program has benefits for multiple user sectors including:

- For State Agencies:
    - A set of tools for:
        - Managing laboratory analytical and field data for all environmental matrices;
        - Electronically receiving laboratory reports; which eliminates data entry;
        - Receiving and vetting electronic data deliverables (EDDs) from industry;
        - Analyzing data through various statistical and charting output formats and integrated GIS;
        - Alerting scientists when laboratories report sample results that exceed acceptable limits for specific parameters are submitted;
        - Displaying monitoring data from multiple sources and agencies;
        - Use by Oil/Gas and water agencies;
        - Displaying data gathered agency monitoring programs; and
        - Displaying data and locations in a GIS format.

- For Industry:

    - A website for uploading, saving as draft, validating, and submitting EDDs from laboratories to the agency for review under secured login.
- For the Public:
    - A single location to view data vetted by and at the discretion of the agency.

Legacy oil and gas data, whether in paper format or scanned files, is a perennial problem for regulators and other stakeholders alike. While there is no magic bullet that will resolve this issue, states can create multi-year plans for digitizing old data. It is increasingly inexpensive to do so, and all the more important as well development becomes denser and the need to understand subsurface conditions becomes more acute.

Key Message 3: State Progress

As this version of the report shows, states continue to make regulatory progress a touchstone of their oil and gas agency regulations to assure programmatic effectiveness. Whether it involves an overall review of a state's regulations such as the one recently undertaken by the Ohio oil and gas program, or an update to existing regulations due to technological, environmental, or human health and safety concerns, states continually update their regulations to provide the most effective and practical regulatory frameworks for the development of vital oil and natural gas resources.

Appendix 1: Acronyms

Abbreviation	Meaning
ANSI	American National Standards Institute
AOR	Area of Review
API	American Petroleum Institute
ASTM	ASTM International (formerly American Society for Testing and Materials)
BLM	Bureau of Land Management
CAS	Chemical Abstract Service
CASRN	Chemical Abstract Service Registry Number
CBL	Cement Bond Log
CWT	Centralized Waste Treatment
E&P	Exploration and production
FEMA	Federal Emergency Management Administration
GWPC	Ground Water Protection Council
IDEM	Indiana Department of Environmental Management
IDNR	Indiana Department of Natural Resources
IOGCC	Interstate Oil and Gas Compact Commission
MIT	Mechanical Integrity Test
MOA	Memorandum of Agreement
MOU	Memorandum of Understanding
O_2	Oxygen Activation Log
OGAP	Oil and Gas Accountability Project
POTW	Publicly Owned Treatment Works
RBDMS	Risk Based Data Management System
RTS	Radioactive Tracer Survey
SAPT	Standard Annulus Pressure Test
SimOPS	Simultaneous Operations
SPE	Society of Petroleum Engineers
TDS	Total Dissolved Solids
UIC	Underground Injection Control
USDOE	United States Department of Energy
USDW	Underground Source of Drinking Water
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VDL	Variable Density Log

Appendix 2: Terms

Term	Meaning
Annulus	The space between a casing string and a wellbore or between two casing strings.
Cleanup	The process of removing contaminants from media such as soil or water through processes that may include bioremediation or collection and disposal.
Containment dike	A natural or artificial containment structure surrounding tanks designed to contain fluids that may leak from a tank or tanks.
Cuttings	The rock material brought to the surface as a consequence of the drilling process. Typically consists of rock fragments and drilling fluids.
Groundwater	Water residing in the subsurface matrix including interstitial spaces, fractures, or vugs. Includes both confined and unconfined strata.
Hydraulic fracturing	The process of fracturing rock using a combination of fluids and solids emplaced in the formation under sufficient pressure to separate the rock matrix.
Permitting	A process used by regulatory agencies to authorize an activity.
Pit	An impoundment designed to hold fluids.
Produced Water	Water that is brought to the surface in connection with oil and gas production. The terms brine, saltwater, and flowback are synonymous with the term produced water.
Remediation	The process of removing contaminants such as produced water or oil from a media such as soil or water. Example: Bioremediation involves the use of biological amendments, hydration and aeration to remove oil from soil through digestion of the oil.
Spill	The uncontained release of fluids.
Tank bottoms	The sediment and water that collects at the bottom of an oil storage tank.
Tanks	Above ground manufactured containers used to store oil and water.
Temporary abandonment	The formal process used by regulatory agencies to allow a well to remain in an inactive status for extended periods of time.
Well integrity	A term that describes the state of a well that has the ability to prevent the migration or release of fluids through the wellbore, casing or cement.
Workover	The process of performing major maintenance or remedial treatments on an oil or gas well." (Schlumberger Oilfield Glossary)

Appendix 3: Typical FracFocus Disclosure in Systems Format

Hydraulic Fracturing Fluid Product Component Information Disclosure

Job Start Date:	2/11/2017
Job End Date:	2/21/2017
State:	Colorado
County:	Weld
API Number:	05-123-41184-00-00
Operator Name:	PDC Energy
Well Name and Number:	Jacobucci 32O-203
Latitude:	40.00696000
Longitude:	-104.91567000
Datum:	NAD83
Federal Well:	NO
Indian Well:	NO
True Vertical Depth:	7,601
Total Base Water Volume (gal):	5,653,124
Total Base Non Water Volume:	0

Hydraulic Fracturing Fluid Composition:

Trade Name	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by mass)**	Maximum Ingredient Concentration in HF Fluid (% by mass)**	Comments
Fresh Water	Operator	Base Fluid					
			Water	7732-18-5	100.00000	86.60804	Density = 8.330
Ingredients	Listed Above	Listed Above					
			Water	7732-18-5	100.00000	1.02051	
Cla-Web(TM)	Halliburton	Additive					
				Listed Below			
CAT-3 ACTIVATOR	Halliburton	Activator					
				Listed Below			
LOSURF-300D	Halliburton	Non-ionic Surfactant					
				Listed Below			
MBC-514	SmartChem	Biocide					
				Listed Below			
SAND-COMMON WHITE-100 MESH, SSA-2, BULK (100003676)	Halliburton	Proppant					
				Listed Below			
BA-20 BUFFERING AGENT	Halliburton	Buffer					
				Listed Below			
WG-18 GELLING AGENT	Halliburton	Gelling Agent					
				Listed Below			
HAI-404M(TM)	Halliburton	Corrosion Inhibitor					
				Listed Below			
SAND-PREMIUM WHITE-30/50, BULK	Halliburton	Proppant					
				Listed Below			
OilPerm FMM-1	Halliburton	Surfactant					
				Listed Below			
VICON NF BREAKER	Halliburton	Breaker					
				Listed Below			
FR-76	Halliburton	Friction Reducer					
				Listed Below			
CL-23 CROSSLINKER	Halliburton	Crosslinker					
				Listed Below			
HCL >10%	Halliburton	Solvent					
				Listed Below			

Appendix 3: Typical FracFocus Disclosure in Systems Format (Cont'd)

Items above are Trade Names with the exception of Base Water . Items below are the individual ingredients.							
			Crystalline silica, quartz	14808-60-7	100.00000	12.00714	
			Hydrochloric acid	7647-01-0	30.00000	0.20073	
			Guar gum derivative	Proprietary	100.00000	0.14705	
			Sodium chloride	7647-14-5	30.00000	0.08122	
			Ammonium acetate	631-61-8	100.00000	0.05894	
			Ethanol	64-17-5	60.00000	0.03449	
			Chlorous acid, sodium salt	7758-19-2	10.00000	0.02671	
			Acetic acid	64-19-7	30.00000	0.01727	
			Zirconium, acetate lactate oxo ammonium complexes	68909-34-2	60.00000	0.01655	
			Hydroxyalkylammonium chloride	Proprietary	60.00000	0.01314	
			Citrus, extract	94266-47-4	10.00000	0.01124	
			Isopropanol	67-63-0	10.00000	0.01124	
			Fatty acids, coco, reaction products with ethanolamine, ethoxylated	61791-08-0	10.00000	0.01124	
			Ammonium chloride	12125-02-9	30.00000	0.00828	
			Acrylamide acrylate copolymer	Proprietary	30.00000	0.00817	Denise Tuck, Halliburton, 3000 N. Sam Houston Pkwy E., Houston, TX 77032, 281-871-6226
			Inorganic salt	Proprietary	30.00000	0.00817	
			Hydrotreated light petroleum distillate	64742-47-8	30.00000	0.00817	
			Sodium bicarbonate	144-55-8	5.00000	0.00735	
			EDTA/Copper chelate	Proprietary	30.00000	0.00620	
			Terpene hydrocarbon by-products	68956-56-9	5.00000	0.00562	
			Poly(oxy-1,2-ethanediyl),alpha-(4-nonylphenyl)-omega-hydroxy-,branched	127087-87-0	5.00000	0.00562	
			Heavy aromatic petroleum naphtha	64742-94-5	5.00000	0.00562	
			Glutaraldehyde	111-30-8	14.00000	0.00411	
			Silica, amorphous - fumed	7631-86-9	1.00000	0.00147	
			Quaternary amine	Proprietary	5.00000	0.00134	
			Naphthalene	91-20-3	1.00000	0.00112	
			Isopropanol	67-63-0	30.00000	0.00112	
			Methanol	67-56-1	30.00000	0.00112	
			Aldehyde	Proprietary	30.00000	0.00112	
			Naphthenic acid ethoxylate	68410-62-8	30.00000	0.00112	
			Alkyl dimethyl benzyl ammonium chloride (C 12-16)	68424-85-1	2.50000	0.00073	
			Oxylated phenolic resin	Proprietary	30.00000	0.00045	
			Fatty acids, tall oil	Proprietary	10.00000	0.00037	
			1-(Benzyl)quinolinium chloride	15619-48-4	10.00000	0.00037	
			Polyethoxylated fatty amine salt	61791-26-2	10.00000	0.00037	
			Alcohols, C12-16, ethoxylated	68551-12-2	10.00000	0.00037	
			Benzylheteropolycicle salt	Proprietary	10.00000	0.00037	
			Heavy aromatic petroleum naphtha	64742-94-5	30.00000	0.00034	
			Ethoxylated alkyl amines	Proprietary	5.00000	0.00019	
			Naphthalene	91-20-3	5.00000	0.00006	
			Poly(oxy-1,2-ethanediyl), alpha-(4-nonylphenyl)-omega-hydroxy-, branched	127087-87-0	5.00000	0.00006	
			Amine salts	Proprietary	0.10000	0.00004	
			Sodium iodide	7681-82-5	1.00000	0.00004	
			Ammonium phosphate	7722-76-1	1.00000	0.00004	
			1,2,4 Trimethylbenzene	95-63-6	1.00000	0.00001	

Total Water Volume sources may include various types of water including fresh water, produced water, and recycled water
Information is based on the maximum potential for concentration and thus the total may be over 100%
If you are calculating a percentage of total ingredients do not add the water volume below the green line to the water volume above the green line

ote: For Field Development Products (products that begin with FDP), MSDS level only information has been provided.
gredient information for chemicals subject to 29 CFR 1910.1200(i) and Appendix D are obtained from suppliers Material Safety Data Sheets (MSDS)

In this example the total base water volume of the job is 5,653,124 gallons. This makes up 87.62% of the total job. An additional 12.007% of the job is silica quartz (SIO2) used as a proppant. The remaining +-0.4% of the ingredients in the job is additives such as potassium chloride, hydrochloric acid and others.

Appendix 4: Matrix elements

1 Well and Wellsite Permitting
1A Types of permits (prior, case-specific authorizations) required
1A1 Drilling
1A1a Permits can be denied or delayed if applicant is not in compliance
1A1b Permits can be revoked/ suspended for non-compliance
1A2 Deepening/ Redrilling
1A3 Workover
1A4 Wellpad construction
1A5 Stormwater
2 Hydraulic Fracturing
2A Specific regulations governing practice of hydraulic fracturing
2B Permit required for Treatment, Stimulation or Fracturing (Remove treatment & stimulation from this)
2B1 A review of the area around the wellbore and within the reach of the horizontal axis of the wellbore is required to check for natural and artificial conduits
2B2 A review of the geology and separation interval between the fractured zone and protected groundwater zones is required
2C Notice required prior to hydraulic fracturing
2C1 Agency
2C2 Landowner
2C3 General Public
2C4 Offset operators
2D Specific requirements for hydraulic fracturing
2D1 Specific materials/ chemicals prohibited (e.g. diesel fuel, 2-BE, etc…)
2D2 Agency requires prior submission of specific information about constituents
2D3 Pressure limitations specified
2D4 Minimum depth or distance from protected groundwater required
2D5 Adjacent water well testing and monitoring required
2D6 Monitoring and recording of stimulation operations required throughout the stimulation process
2D7 Cessation of operation is required upon evidence of mechanical integrity breach or failure
2D8 Surface equipment mechanical integrity test before commencement of fracturing or re-fracturing required
2D9 Fracturing fluid must be confined to the target reservoir
2D10 Agency requires additional review where the geology or hydraulic connectivity between the zone being fractured and protected groundwater is not clearly determined or may not be adequate to prevent fluid migration

2D11 Agency requires additional safeguards where a review of the geology or hydraulic connectivity between the zone being fractured and protected groundwater determines such safeguards are needed
2E Post-activity reporting required for hydraulic fracturing
2E1 Volumes
2E2 Additives
2E3 Pressures
2E4 Depths
2E5 Perforation intervals
2E6 Volumes of water used for hydraulic fracturing
2E6a Water volumes required by type (e.g. re-cycled, fresh, brackish, saline etc…)
2E7 FracFocus reporting required
3 Well Integrity
3A Well construction information including hole size and casing size for each string reported
3B Surface casing through and below all protected groundwater zones required
3B1 Cementing from bottom to top required
3B2 Cementing from bottom through all protected groundwater zones required
3B3 Cementing from bottom to specific distance above bottom required
3B4 Centralizers required at intervals sufficient to provide for casing centralization
3B5 Surface casing string is pressure tested prior to drill-out to verify casing integrity
3B6 Formation Integrity Test/Shoe Test following drill-out of surface casing string required
3C Intermediate casing required
3C1 Cementing from bottom to top required
3C2 Cementing from bottom to next cemented string required
3C3 Cementing from bottom to specific distance above bottom required
3C4 Cementing of casing as necessary to isolate protected groundwater encountered below the casing seat required
3C5 Cementing of casing as necessary to isolate flow zones capable of over-pressurizing any casing annulus or adversely affecting the cement job required
3C6 Cementing of casing as necessary to isolate corrosive zones required
3C7 Minimum standard for the height of cement above the zones that are sealed and isolated required
3C8 Centralizers required at intervals sufficient to provide for casing centralization
3C9 Casing string must be pressure tested prior to drill-out to verify casing integrity
3C10 Formation Integrity Test/Shoe Test following drill-out of intermediate casing string required
3D Long/Production string casing required
3D1 Cementing from bottom to top required
3D2 Cementing from bottom to next cemented string required
3D3 Cementation from bottom to specific distance above bottom required

3D4 Cementing of casing as necessary to isolate protected groundwater encountered below the surface casing seat required
3D5 Cementing of casing as necessary to isolate flow zones capable of over-pressurizing any casing annulus or adversely affecting the cement job required
3D6 Cementing of casing as necessary to isolate corrosive zones required
3D7 Minimum standard for the height of cement above the zones that are sealed and isolated required
3D8 Centralizers required at intervals sufficient to provide for casing centralization
3D9 Casing string must be pressure tested after setting to verify casing integrity
3E Casing standards provided
3E1 Casing must meet API Standards
3E2 Casing must be properly rated for expected conditions
3E3 Specific regulations for use of reconditioned casings
3F Cement standards provided
3F1 Cement must meet API standards
3F2 Established limit on free water in cement
3F3 Mix water quality is evaluated with respect to the cement being used
3F4 Authority to require specific blends to isolate problematic zones
3F5 Cement slurry must be mixed and pumped at a rate to maintain consistent density
3G Cement evaluation logs or other approved testing methods are required under specifically defined circumstances
3H Cement set-up period (Wait On Cement time) to achieve compressive strength required before resuming drilling
3I Does the rule place a limitation on the constituents of drilling fluids for surface casing
3I1 Oil based muds prohibited
3I2 Use of produced water prohibited (Consider re-word to say use of non-fresh water)
3J Operator required to notify agency or agency representative prior to installing casing and/or commencing cementing operations
3K Borehole conditioning required
3K1 Mud removal prior to cement emplacement required
3K2 Circulation must be established prior to commencement of cementing, if technically feasible
3K3 If circulation cannot be established, standards address how cement seals will be emplaced to effectively isolate specified zones
3K4 Borehole must be essentially static prior to cement circulation
3L Casing pressure test at a pressure greater than the anticipated fracture pressure required prior to fracturing
3M Minimum annular space of at least 0.75”, between each wellbore and casing, or each casing/ casing annulus required
3N Corrective action required if there are circulation problems or other indicators of deficient/defective cement
3O Kick reporting required during drilling

4 Temporary Abandonment
4A Temporary abandonment specified
4B Prior authorization required
4C Renewal specified
4D Duration of TA/ Shut-in status limited
4E Casing pressure test or specific construction required
5 Production Operations
5A Post-completion tubing, casing, or Braden head pressures monitoring by operator required
5B Piping, valves, flow lines inspections by operator required
5C Other appurtenances (oil/water separators, heater treaters, etc.) inspections by operator 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) when consistent with performance objectives Note: Except for spacers
6D Cement placement above producing zones required
6E Cement placement across all protected water zones required
6F Wellbore must be essentially static at the time cement plugs are emplaced
6G Bridge plugs required under specific circumstances
6H Standards specify the thickness and spacing of required plugs
6I Plugging plan submission prior to plugging required
6J Standards specify when and how the plugs must be tagged or tested
6K Timeframes established for plugging dry holes, inactive wells
6L Notice of intent to plug required
6M Witnessing
6M1 Witnessing required
6M2 Cement tickets specified in lieu of witnessing
6N Plug tagging/ placement verification required
6O Cement plug strength specified
6P Plugging method specified
6P1 Pump and plug specified
6P2 Dump bailing prohibited
6P3 Bullhead plugging prohibited
6Q Reporting required
6Q1 Cement type (e.g. Class A)
6Q2 Cement volume (e.g. Sacks or Cu. Ft.)
6Q3 Bridge plugs (e.g. CIBP, Cement Retainer etc…)
6Q4 Casing left
6Q5 Plug placement intervals

6Q6 Timeframe for reporting established
7 Storage in Pits
7A Pit types specified
7A1 Drilling/ workover
7A2 Produced water storage
7A3 Waste storage
7A4 Emergency
7A5 Burn Off
7A6 Temporary oil storage
7B Drilling/Workover Pits
7B1 Prior Authorization Required
7B2 Prior surface owner notification required
7B3 Inspection before use required
7B4 Construction requirements
7B4a General
7B4b Specific
7B4b1 Design requirements for drilling pits
7B4b2 Modular, site-assembled containment structures prohibited
7B4b3 Leak detection
7B4c Liners required
7B4c1 Liner inspection in lieu of direct leak detection methods specified
7B4c2 Compatibility of liner with stored fluids and setting evaluated
7B4c4 Artificial specified
7B4c3 Natural allowed
7B4c5 Competency standards specified
7B4c6 Seaming standards specified
7B4c7 Bed preparation standards specified
7B4c8 Reporting of detected leaks required
7B4c9 Corrective action in response to leaks required
7B5 Freeboard required
7B6 Siting or Setback requirements
7B6a Setback from surface water specified
7B6b Prohibited in water table
7B6c Vertical separation from high water table specified
7B6d Siting within 100 year floodplain and/ or in floodway limited
7B6e Setback from drinking water wells specified
7B7 Operator inspection during operation required
7B8 Duration of use regulated
7B9 Closure requirements
7B9a Prior authorization required

7B9b Prior notice to surface owner required
7B9c Soil sampling required
7B9d Closure report required
7B9e Site restoration to prior use mandated
7B9f Closure can be waived with landowner permission
7B9g Specification regarding disposition of pit contents
7B9h Specification regarding disposition of pit liner
7C Produced water storage pits
7C1 Prior Authorization Required
7C2 Prior surface owner notification required
7C3 Inspection before use required
7C4 Construction requirements
7C4a General
7C4b Specific
7C4b1 Design requirements for storage pits
7C4b2 Modular, site-assembled containment structures prohibited
7C4b3 Leak detection
7C4c Liners required
7C4c1 Liner inspection in lieu of direct leak detection methods specified
7C4c2 Compatibility of liner with stored fluids and setting evaluated
7C4c4 Artificial specified
7C4c3 Natural allowed
7C4c5 Competency standards specified
7C4c6 Seaming standards specified
7C4c7 Bed preparation standards specified
7C4c8 Reporting of detected leaks required
7C4c9 Corrective action in response to leaks required
7C5 Freeboard required
7C6 Siting or Setback requirements
7C6a Setback from surface water specified
7C6b Prohibited in water table
7C6c Vertical separation from high water table specified
7C6d Siting within 100 year floodplain and/ or in floodway limited
7C6e Setback from drinking water wells specified
7C7 Operator inspection during operation required
7C8 Duration of use regulated
7C9 Closure requirements
7C9a Prior authorization required
7C9b Prior notice to surface owner required
7C9c Soil sampling required

7C9d Closure report required
7C9e Site restoration to prior use mandated
7C9f Closure can be waived with landowner permission
7C9g Specification regarding disposition of pit contents
7C9h Specification regarding disposition of pit liner
7D Centralized storage pits regulated separately from on-site pits
8 Storage in Tanks (Above grade)
8A Prior authorization required
8B Operator inspection of tanks required
8B1 Before use
8B2 During use
8C Design and construction standards established
8C1 Tank materials specified
8C2 ASTM, ANSI, API or other technical specifications required
8C3 Maximum volume per tank specified
8C4 Maximum aggregate tank volume per site specified
8C5 Tanks with 10% or more volume (including piping) below ground surface prohibited
8C6 External level meters/monitors required
8C7 Overfill controls required
8C8 Pre-construction plans must be submitted to agency
8C9 Spill containment at fluid transfer points required
8C10 Leak detection
8C10a Leak detection equipment required
8C10b Routine internal inspection required
8D Siting or setback required
8D1 Setback from surface water specified
8D2 Depth to ground water considered
8D3 Siting within 100 year floodplain and/ or in floodway limited
8D4 Setback from drinking water wells specified
8E Secondary containment required
8E1 Capacity specified
8E2 Permeability specified
8E3 Maintenance and on-going inspections required
8E4 Standing fluids in containment area prohibited
8F Closure requirements
8F1 Prior authorization required
8F2 Prior notice to surface owner required
8F3 Soil sampling required
8F4 Closure report required
8F5 Site restoration to prior use mandated

8F6 Closure can be waived with landowner permission
8F7 Specifications regarding disposition of tank contents
8F8 Specifications regarding disposition of tanks
9 Transportation of Produced Water by Truck or Pipeline for Disposal
9A Permitting or authorization of produced water transporters required
9A1 Trucks
9A2 Pipelines
9B Manifests/trip tickets recording volume of produced water transported off-site required
9C Final disposition of produced water reported
10 Produced Water Reuse for Oil and Gas E&P
10A Produced water treatment specifically regulated
10A1 Regulations specific to side streams (solid and liquid) generated as part of produced water treatment
10A2 Chemical characterization of side streams (solid and liquid) required
10B Produced water used for purposes other than well stimulation specified
10C Produced water used for drilling mud for drilling of surface casing portion of the well prohibited
10D Regulations specific to produced water pipelines
10E Permitting, reporting, and siting of produced water pipelines required
10E1 Permit or authorization required
10E2 Locations reported
10E3 Siting requirements
10F Specific design, construction, and operation requirements for produced water pipelines
10F1 Design and construction standards established
10F2 Initial integrity testing required
10F3 Routine integrity assessment required
10F3a Visual inspection required
10F3b Flow and pressure monitoring required
10F3c Other leak detection required
10F4 Reinspection and testing after pipeline repairs prior to resuming operation required
10F5 Duration of use established
10G Produced water pipeline decommissioning or removal specified
11 Exempt Waste Disposition
11A On site- disposal of waste regulated
11A1 Permit required
11A2 Specific waste constituents regulated
11A3 Quantities of waste disposed on-site reported
11A4 Location of disposal site reported
11A5 Practice prohibited
11B Application of produced water to roads regulated

11B1 Permit required
11B2 Application rates specified
11B3 Quantities of material applied reported
11B4 Practice prohibited
11C Application of tank bottoms and waste oil to roads regulated
11C1 Permit required
11C2 Application rates specified
11C3 Quantities of material applied reported
11C4 Practice prohibited
11D Application of produced water to lands regulated
11D1 Permit required
11D2 Application rates specified
11D3 Quantities of material applied reported
11D4 Practice prohibited
11E Application of tank bottoms and waste oil to lands regulated
11E1 Permit required
11E2 Application rates specified
11E3 Quantities of material applied reported
11E4 Practice prohibited
11F On-site disposal of drill cuttings regulated
11F1 Practice prohibited
11G Beneficial re-use of drill cuttings regulated
11G1 Practice prohibited
11H Off-site disposal of drill cuttings regulated
11I Beneficial reuse of produced water *not* for oil and gas E&P regulated
11J Permit required for disposal via offsite treatment facility
12 Spill Response
12A Spills regulated by the agency
12B Agency notification of spills required
12B1 Volume of spill threshold to trigger notification
12B2 Reporting time limit specified
12B3 Follow-up notification with details required
12C Landowner notification of spills required
12C1 Volume of spill threshold to trigger notification
12C2 Reporting time limit specified
12D Spill remediation regulated
12D1 Clean-up standards reflect the material spilled
12D2 Quantified clean-up standards specified

Appendix 5: Considerations Chart

Element	Considerations
Permitting	1(a): For states where topography, weather patterns or other factors pose challenges for well pad construction, rules that mitigate those issues.
Hydraulic Fracturing	1(b): Mechanical Integrity Testing requirements prior to well stimulation 1(c): Monitoring and reporting requirements during well stimulation, and suspension of well stimulation when mechanical or formation integrity is compromised 1(d): Analysis of confining zone(s) and "Area of Review"-style analysis of near wellbore geology to mitigate risk of conduits transmitting hydraulic fracturing fluids 1(e): Defining the meaning of simultaneous operations (SimOPS) relative to hydraulic fracturing. NOTE: Although listed under hydraulic fracturing, SimOPS is also relevant to other field activities. 1(f): Reporting volumes of water used by type (e.g., Produced water, groundwater, fresh water etc…)
Well Integrity	1(g): Comprehensive well integrity testing during construction, especially Formation Integrity Testing (or "shoe" testing) prior to drill out 1(h): Centralization standards for production/long string 1(i): Providing standards for reconditioned casing 1(j): Specifying mix-water quality standards and requirements for free water content in cement 1(k): Assuring cement is mixed, and pumped at a rate, to maintain consistent density 1(l): Reporting of "kicks" during drilling to ensure well control oversight and to establish a better understanding of potential over-pressurized zones 1(m): Standards for annular space minimums between casing strings and between strings and formation
Temporary Abandonment	1(n): Monitoring of wells in TA status to ensure they maintain mechanical integrity 1(o): Establishing a maximum time duration within which a well may remain in TA status
Production Operations	1(p): Bradenhead monitoring requirements to facilitate lifetime well integrity management 1(q): Requirements for operator inspections of piping, valves, flow lines and other appurtenances during operations
Storage in Pits	1(r): Requirements should address siting, design, construction, operations, and closure of pits 1(s): Competency standards for liners 1(t): Inspections prior to use and during operations 1(u): Leak detection requirements
Storage in Tanks	1(v): Requirements should address siting, design, construction, operations, testing, and closure of tanks 1(w): Tank material should be compatible with stored fluids
Well Plugging	1(x): Cement placement across all protected water zones 1(y) Witnessing of well plugging operations by agency representatives 1(z) Tagging of plugs where needed to assure proper placement

Transportation of Produced Water by Truck or Pipeline for Disposal	1(aa): Permitting or licensing of produced water transporters and the recording of produced water volumes transported off-site 1(bb): Tracking and reporting of final disposition
Produced Water Reuse for Oil and Gas E&P	1(cc): Chemical characterization and management of side streams such as treatment residuals 1(dd): Regulation of use of produced water for uses in the oilfield other than well stimulation 1(ee): Siting, design, construction, operations, and closure standards for produced water pipelines
Exempt Waste Disposition	1(ff): Manifests for off-site disposal where appropriate
Spill Response	1(gg): Clean-up standards should be established that are quantitative and relative to the characteristics of the material spilled and the media impacted 1(hh): Follow up notification details to improve performance

Appendix 6: Comparison of Pits and Tanks

Drilling and produced fluids can be stored in either pits or tanks. Each has advantages and disadvantages when it comes to managing risk, as outlined in the following table.

	Advantage	
Risk Categories	**Pits**	**Tanks**
Shallow groundwater contamination	-	-
Catastrophic failure	X	
Leak detection		X
Maintenance		X
Volume of storage	X	
Protection of wildlife		X
Protection from illegal dumping		X
Protection from acts of vandalism	X	
Loss of contents from flooding	-	-
Fire potential	X	
Confined entry risk	X	
Ease of closure and site remediation	-	-

A relative disadvantage in a storage method can be negated or even changed to an advantage by an additional design or operational component. For example, while pits can store a much larger volume of fluid than tanks on a per-barrel-cost basis, they have a greater potential for shallow groundwater contamination since they may be excavated into the ground and since their larger footprint cannot be visibly inspected, making it difficult to identify leaks quickly. However, a pit with an active leak detection system may have an advantage over a tank or tank battery with no leak detection. An active leak detection system also simplifies pit maintenance since it provides the ability to continually monitor liner integrity without the need for draining of the pit. Conversely, while it is easier to monitor for smaller leaks in tank systems, tanks are more prone to catastrophic failures, which can result in the release of much larger volumes of fluids in a single event. Also, while tanks are easier to maintain due to their accessibility, they typically require more frequent maintenance because of their exposure to the weather, exposure to potential corrosive properties of the material stored, and potential for vandalism.

Determining which fluid storage system to use in a specific circumstance involves an evaluation of the unique aspects of the location, purpose, and usage. In locations where groundwater is deeper and there are natural clay barriers between the surface and subsurface, pits may be a good option for temporary or even long-term storage of produced water and exempt waste. Conversely, where groundwater is shallow or there are few barriers to downward migration of fluids, tanks may provide a better option for fluid storage. While it might appear that tank systems are the most environmentally protective in all cases, this is not borne out by the evidence. Each fluid storage system has plusses and minuses which makes it important that the decision regarding their use be made on a case by case basis.

Explanations of the tanks versus pits ratings are given below.

Shallow groundwater contamination

Although tanks are set above ground and typically surrounded by containment dikes designed to hold the contents of a spill or leak, they can pose a risk of contamination to shallow groundwater from leaks (especially those on the underside of the tank). Pits can be excavated to depths that are in close proximity to shallow groundwater. The presence of a leak detection system and routine inspection and maintenance will provide a distinct advantage to a storage facility (pit or tank) over a facility without these design and operational components. *Advantage neither*

Catastrophic failure

Pits are less prone to catastrophic failure than tanks. Pit liners can leak and result in migration of fluids from the inside of the pit. However, the complete failure of a pit liner in a manner resulting in a total loss of pit contents is rare. With respect to tanks, while the most common failure involves small leaks, a complete failure of a tank that has not been subject to routine inspection and maintenance is possible. *Advantage pits*

Leak detection

Unless a leak is occurring on the bottom of a tank where it cannot be seen, it is easy to detect leaks in tank systems, including the tanks and associated piping. With respect to leaks from the bottom of tanks, leak detection systems are available, and if inflows and outflows can be accurately determined, routine gauging of the tanks can be used to detect leaks. Further, overfilling of tanks can be managed by automated systems, which are much more difficult to install and use in pits. *Advantage tanks*

Ease of maintenance

In order to fully maintain pits, it is necessary to drain their contents and inspect the pit liner, and when necessary, remove and replace liner systems. This is a costly and time-consuming process and involves the need to temporarily store potentially large volumes of fluids from the pit, which can result in the need to place significant numbers of temporary tanks on site for storage. Tanks require maintenance such as painting, patching, and sometimes replacement, and they also need to be periodically drained and inspected so that any internal deterioration can be identified. However, the accessibility of tanks makes these jobs easier to manage and the smaller volumes of fluids in individual tanks reduce the need for large numbers of temporary tanks whenever draining for inspection and maintenance is required. *Advantage tanks*

Volume of storage

Tanks have a limited storage capacity. In locations where large volumes of fluid are produced or handled, the use of tanks is more difficult and costly due to the number of tanks needed. Pits can easily handle much larger fluid volumes at a more reasonable cost. *Advantage pits*

Protection of wildlife

Although it is common to net and fence pits, this practice can be more difficult if a pit has a large surface area. Closed-top tanks prevent the introduction of wildlife. *Advantage tanks*

Protection from illegal dumping

Closed-top tanks discourage disposal of unauthorized or improper fluids. Pits that are not fenced off from the public provide an inviting location to dump illegal substances. *Advantage tanks*

Protection from acts of vandalism

With their readily accessible valves, flowlines, above-ground profiles, and oftentimes catwalks, tanks are an inviting target for persons bent on mayhem. Tanks can be damaged and their contents readily released by a well-placed sledge hammer strike to a valve. In contrast, pits do not present an inviting target for a vandal. Removing fluids from a pit would be time-consuming and would require that a vandal have access to a high-capacity pump with discharge and intake lines. *Advantage pits*

Loss of contents from flooding

Any structure within the boundaries of a floodplain is susceptible to flooding. While construction details (e.g., the height of the berm of a pit or containment dike of a tank or tank battery) can protect the storage facility from rising water levels, neither pits nor tanks can be expected to withstand flowing flood waters and debris. *Advantage neither*

Fire potential

Both pits and tanks have the potential to be affected by fires. However, flammable surface contents in an open pit can typically be allowed to burn out, posing a low risk of injury or death. In contrast, fires in a tank battery can result in substantial damage from tank explosions and failures of the tank resulting in total loss of tank contents. Further, a tank failure resulting from a fire places all other tanks in a tank battery at risk, multiplying the overall risk. *Advantage pits*

<u>Confined space entry</u>

Pits, by their nature, are open to the air and do not subject individuals to risks associated with confined space entry. Conversely, tanks are closed units that can capture and hold noxious gases. This problem is especially notable where produced fluids contain hydrogen sulfide. *Advantage pits*

<u>Ease of closure and site remediation</u>

Both pits and tanks have unique closure and remediation issues. Pits must be drained and the fluids properly disposed of liners removed and disposed of or shredded and interred, and the pit backfilled, graded, and sometimes seeded. Tanks must have their contents removed and properly disposed of the tanks removed, the site leveled and graded, and the soils either removed and properly disposed of or remediated in place. *Advantage neither*

Appendix 7: 2012 State Permitting Survey for Wells on Federal Land

In 2012 the GWPC surveyed 15 states with significant amounts of federally controlled land to determine if the state issued a drilling permit in addition to the permit issued by the Bureau of Land Management (BLM). The results of this survey are contained in the following table. *NOTE: Due to time and resource constraints this survey was not repeated for either the 2017 or 2021 editions of this report.*

State	State Issues Drilling Permit on Federal Land
Alaska	Y
Arizona	Y
California	N
Colorado	Y
Kansas	Y
Montana	Y for record purposes only
Nebraska	Y
Nevada	Y in coordination w/ BLM
New Mexico	Y but use BLM APD forms
North Dakota	Y
Oklahoma	N
South Dakota	Y
Texas	Y
Utah	Y but accept BLM APD forms
Wyoming	Y

Appendix 8: MOU between the TRRC and TCEQ

§3.30 Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)

(a) Need for agreement. Several statutes cover persons and activities where the respective jurisdictions of the RRC and the TCEQ may intersect. This rule is a statement of how the agencies implement the division of jurisdiction.

(1) Section 10 of House Bill 1407, 67th Legislature, 1981, which appeared as a footnote to the Texas Solid Waste Disposal Act, Texas Civil Statutes, Article 4477-7, provides as follows: On or before January 1, 1982, the Texas Department of Water Resources, the Texas Department of Health, and the Railroad Commission of Texas shall execute a memorandum of understanding that specifies in detail these agencies' interpretation of the division of jurisdiction among the agencies over waste materials that result from or are related to activities associated with the exploration for and the development, production, and refining of oil or gas. The agencies shall amend the memorandum of understanding at any time that the agencies find it to be necessary.

(2) Texas Health and Safety Code, §401.414, relating to Memoranda of Understanding, requires the Railroad Commission of Texas and the Texas Commission on Environmental Quality to adopt a memorandum of understanding (MOU) defining the agencies' respective duties under Texas Health and Safety Code, Chapter 401, relating to radioactive materials and other sources of radiation. Texas Health and Safety Code, §401.415, relating to oil and gas naturally occurring radioactive material (NORM) waste, provides that the Railroad Commission of Texas shall issue rules on the management of oil and gas NORM waste, and in so doing shall consult with the Texas Natural Resource Conservation Commission (now TCEQ) and the Department of Health (now Department of State Health Services) regarding protection of the public health and the environment.

(3) Texas Water Code, Chapters 26 and 27, provide that the Railroad Commission and TCEQ collaborate on matters related to discharges, surface water quality, groundwater protection, underground injection control and geologic storage of carbon dioxide. Texas Water Code, §27.049, relating to Memorandum of Understanding, requires the RRC and TCEQ to adopt a new MOU or amend the existing MOU to reflect the agencies' respective duties under Texas Water Code, Chapter 27, Subchapter C-1 (relating to Geologic Storage and Associated Injection of Anthropogenic Carbon Dioxide).

(4) The original MOU between the agencies adopted pursuant to House Bill 1407 (67th Legislature, 1981) became effective January 1, 1982. The MOU was revised effective December 1, 1987, May 31, 1998, August 30, 2010, and again on May 1, 2012, to reflect legislative clarification of the Railroad Commission's jurisdiction over oil and gas wastes and the Texas Natural Resource Conservation Commission's (the combination of the Texas Water Commission, the Texas Air Control Board, and portions of the Texas Department of Health) jurisdiction over industrial and hazardous wastes.

(5) The agencies have determined that the revised MOU that became effective on May 1, 2012, should again be revised to further clarify jurisdictional boundaries and to reflect legislative changes in agency responsibility.

(b) General agency jurisdictions.

(1) Texas Commission on Environmental Quality (TCEQ) (the successor agency to the Texas Natural Resource Conservation Commission).

(A) Solid waste. Under Texas Health and Safety Code, Chapter 361, §§361.001 - 361.754, the TCEQ has jurisdiction over solid waste. The TCEQ's jurisdiction encompasses hazardous and nonhazardous, industrial and municipal, solid wastes.

(i) Under Texas Health and Safety Code, §361.003(34), solid waste under the jurisdiction of the TCEQ is defined to include "garbage, rubbish, refuse, sludge from a waste treatment plant, water supply treatment plant, or air pollution control facility, and other discarded material, including solid, liquid, semisolid, or contained gaseous material resulting from industrial, municipal, commercial, mining, and agricultural operations and from community and institutional activities."

(ii) Under Texas Health and Safety Code, §361.003(34), the definition of solid waste excludes "material which results from activities associated with the exploration, development, or production of oil or gas or geothermal resources and other substance or material regulated by the Railroad Commission of Texas pursuant to Section 91.101, Natural Resources Code. . . ."

(iii) Under Texas Health and Safety Code, §361.003(34), the definition of solid waste includes the following until the United States Environmental Protection Agency (EPA) delegates its authority under the Resource Conservation and Recovery Act, 42 United States Code (U.S.C.) §6901, et seq., (RCRA) to the RRC: "waste, substance or material that results from activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants and is a hazardous waste as defined by the administrator of the EPA. . . ."

(iv) After delegation of RCRA authority to the RRC, the definition of solid waste (which defines TCEQ's jurisdiction) will not include hazardous wastes arising out of or incidental to activities associated with gasoline plants, natural gas or natural gas liquids processing plants, or reservoir pressure maintenance or repressurizing plants. The term natural gas or natural gas liquids processing plant refers to a plant the primary function of which is the extraction of natural gas liquids from field gas or fractionation of natural gas liquids. The term does not include a separately located natural gas treating plant for which the primary function is the removal of carbon dioxide, hydrogen sulfide, or other impurities from the natural gas stream. A separator, dehydration unit, heater treater, sweetening unit, compressor, or similar equipment is considered a part of a natural gas or natural gas liquids processing plant only if it is located at a plant the primary function of which is the extraction of natural gas liquids from field gas or fractionation of natural gas liquids. Further, a pressure maintenance or repressurizing plant is a plant for processing natural gas for reinjection (for reservoir pressure maintenance or repressurization) in a natural gas recycling project. A compressor station along a natural gas pipeline system or a pump station along a crude oil pipeline system is not a pressure maintenance or repressurizing plant.

(B) Water quality.

(i) Discharges under Texas Water Code, Chapter 26. Under the Texas Water Code, Chapter 26, the TCEQ has jurisdiction over discharges into or adjacent to water in the state, except for discharges regulated by the RRC. Upon delegation from the United States Environmental Protection Agency to the TCEQ of authority to issue permits for discharges into surface water in the state of produced water, hydrostatic test water, and gas plant effluent resulting from the activities described in Texas Water Code §26.131(a), the TCEQ has sole authority to issue permits for those discharges. For the purposes of TCEQ's implementation of Texas Water Code, §26.131,"produced water" is defined as all wastewater associated with oil and gas exploration, development, and production activities, except hydrostatic test water and gas plant effluent, that is discharged into water in the state, including waste streams regulated by 40 CFR Part 435.

(ii) Discharge permits existing on the effective date of EPA's delegation to TCEQ of NPDES permit authority for discharges of produced water, hydrostatic test water, and gas plant effluent. RRC permits issued prior to TCEQ delegation of NPDES authority shall remain effective until revoked or expired. Amendment or renewal of such permits on or after the effective date of delegation shall be pursuant to TCEQ's TPDES authority. The TPDES permit will supersede and replace the RRC permit. For facilities that have both an RRC permit and an EPA permit, TCEQ will issue the TPDES permit upon amendment or renewal of the RRC or EPA permit, whichever occurs first.

(iii) Discharge applications pending on the effective date of EPA's delegation to TCEQ of NPDES permit authority for discharges of produced water, hydrostatic test water, and gas plant effluent. TCEQ shall assume authority for discharge applications pending at the time TCEQ receives delegation from EPA. The RRC will provide TCEQ the permit application and any other relevant information necessary to administratively and technically review and process the applications. TCEQ will review and process these pending applications in accordance with TPDES requirements.

(iv) Storm water. TCEQ has jurisdiction over storm water discharges that are required to be permitted pursuant to Title 40 Code of Federal Regulations (CFR) Part 122.26, except for discharges regulated by the RRC. Discharge of storm water regulated by TCEQ may be authorized by an individual Texas Pollutant Discharge Elimination System (TPDES) permit or by a general TPDES permit. These storm water permits may also include authorizations for certain minor types of non-storm water discharges.

(I) Storm water associated with industrial activities. The TCEQ regulates storm water discharges associated with certain industrial activities under individual TPDES permits and under the TPDES Multi-Sector General Permit, except for discharges associated with industrial activities under the jurisdiction of the RRC.

(II) Storm water associated with construction activities. The TCEQ regulates storm water discharges associated with construction activities, except for discharges from construction activities under the jurisdiction of the RRC.

(III) Municipal storm water discharges. The TCEQ has jurisdiction over discharges from regulated municipal storm sewer systems (MS4s).

(IV) Combined storm water. Except with regard to storage of oil, when a portion of a site is regulated by the TCEQ, and a portion of a site is regulated by the EPA and RRC, storm water authorization must be obtained from the TCEQ for the portion(s) of the site regulated by the TCEQ, and from the EPA and the RRC, as applicable, for the RRC regulated portion(s) of the site. Discharge of storm water from a facility that stores both refined products intended for off-site use and crude oil in aboveground tanks is regulated by the TCEQ.

(v) State water quality certification. Under the Clean Water Act (CWA) Section 401 (33 U.S.C. Section 1341), the TCEQ performs state water quality certifications for activities that require a federal license or permit and that may result in a discharge to waters of the United States, except for those activities regulated by the RRC.

(vi) Commercial brine extraction and evaporation. Under Texas Water Code, §26.132, the TCEQ has jurisdiction over evaporation pits operated for the commercial production of brine water, minerals, salts, or other substances that naturally occur in groundwater and that are not regulated by the RRC.

(C) Injection wells. Under the Texas Water Code, Chapter 27, the TCEQ has jurisdiction to regulate and authorize the drilling, construction, operation, and closure of injection wells unless the activity is subject to the jurisdiction of the RRC. Injection wells under TCEQ's jurisdiction are identified in 30 TAC §331.11 (relating to Classification of Injection Wells) and include:

(i) Class I injection wells for the disposal of hazardous, radioactive, industrial or municipal waste that inject fluids below the lower-most formation which within 1/4 mile of the wellbore contains an underground source of drinking water;

(ii) Class III injection wells for the extraction of minerals including solution mining of sodium sulfate, sulfur, potash, phosphate, copper, uranium and the mining of sulfur by the Frasch process;

(iii) Class IV injection wells for the disposal of hazardous or radioactive waste which inject fluids into or above formations that contain an underground source of drinking water; and

(iv) Class V injection wells that are not under the jurisdiction of the RRC, such as aquifer remediation wells, aquifer recharge wells, aquifer storage wells, large capacity septic systems, storm water drainage wells, salt water intrusion barrier wells, and closed loop geothermal wells.

(2) Railroad Commission of Texas (RRC).

(A) Oil and gas waste.

(i) Under Texas Natural Resources Code, Title 3, and Texas Water Code, Chapter 26, wastes (both hazardous and nonhazardous) resulting from activities associated with the exploration, development, or production of oil or gas or geothermal resources, including storage, handling, reclamation, gathering, transportation, or distribution of crude oil or natural gas by pipeline, prior to the refining of such oil or prior to the use of such gas in any manufacturing process or as a residential or industrial fuel, are under the jurisdiction of the RRC, except as noted in clause (ii) of this subparagraph. These wastes are termed "oil and gas wastes." In compliance with Texas Health and Safety Code, §361.025 (relating to exempt activities), a list of activities that generate wastes that are subject to the jurisdiction of the RRC is found at §3.8(a)(30) of this title (relating to Water Protection) and at 30 TAC §335.1 (relating to Definitions), which contains a definition of "activities associated with the exploration, development, and production of oil or gas or geothermal resources." Under Texas Health and Safety Code, §401.415, the RRC has jurisdiction over the disposal of oil and gas naturally occurring radioactive material (NORM) waste that constitutes, is contained in, or has contaminated oil and gas waste.

(ii) Hazardous wastes arising out of or incidental to activities associated with gasoline plants, natural gas or natural gas liquids processing plants or reservoir pressure maintenance or repressurizing plants are subject to the jurisdiction of the TCEQ until the RRC is authorized by EPA to administer RCRA. When the RRC is authorized by EPA to administer RCRA, jurisdiction over such hazardous wastes will transfer from the TCEQ to the RRC.

(B) Water quality.

(i) Discharges. Under Texas Natural Resources Code, Title 3, and Texas Water Code, Chapter 26, the RRC regulates discharges from activities associated with the exploration, development, or production of oil, gas, or geothermal resources, including transportation of crude oil and natural gas by pipeline, and from solution brine mining activities, except that on delegation to the TCEQ of NPDES authority for discharges into surface water in the state of produced water, hydrostatic test water, and gas plant effluent resulting from the activities described in Texas Water Code §26.131(a), the TCEQ has sole authority to issue permits for those discharges. Discharges regulated by the RRC into or adjacent to water in the state shall not cause a violation of the water quality standards. While water quality standards are established by the TCEQ, the RRC has the responsibility for enforcing any violation of such standards resulting from activities regulated by the RRC. Texas Water Code, Chapter 26, does not require that discharges regulated by the RRC comply with regulations of the TCEQ that are not water quality standards. The TCEQ and the RRC may consult as necessary regarding application and interpretation of Texas Surface Water Quality Standards.

(ii) Storm water. When required by federal law, authorization for storm water discharges that are under the jurisdiction of the RRC must be obtained through application for a National Pollutant Discharge Elimination System (NPDES) permit with the EPA and authorization from the RRC, as applicable.

(I) Storm water associated with industrial activities. Where required by federal law, discharges of storm water associated with facilities and activities under the RRC's jurisdiction must be authorized by the EPA and the RRC, as applicable. Under 33 U.S.C. §1342(l)(2) and §1362(24), EPA cannot require a permit for discharges of storm water from "field activities or operations associated with {oil and gas} exploration, production, processing, or treatment operations, or transmission facilities" unless the discharge is contaminated by contact with any overburden, raw material, intermediate product, finished product, byproduct, or waste product located on the site of the facility. Under §3.8 of this title (relating to Water Protection), the RRC prohibits operators from causing or allowing pollution of surface or subsurface water. Operators are encouraged to implement and maintain Best Management Practices (BMPs) to minimize discharges of pollutants, including sediment, in storm water to help ensure protection of surface water quality during storm events.

(II) Storm water associated with construction activities. Where required by federal law, discharges of storm water associated with construction activities under the RRC's jurisdiction must be authorized by the EPA and the RRC, as applicable. Activities under RRC jurisdiction include construction of a facility that, when completed, would be associated with the exploration, development, or production of oil or gas or geothermal resources, such as a well site; treatment or storage facility; underground hydrocarbon or natural gas storage facility; reclamation plant; gas processing facility; compressor station; terminal facility where crude oil is stored prior to refining and at which refined products are stored solely for use at the facility; a carbon dioxide geologic storage facility under the jurisdiction of the RRC; and a gathering, transmission, or distribution pipeline that will transport crude oil or natural gas, including natural gas liquids, prior to refining of such oil or the use of the natural gas in any manufacturing process or as a residential or industrial fuel. The RRC also has jurisdiction over storm water from land disturbance associated with a site survey that is conducted prior to construction of a facility that would be regulated by the RRC. Under 33 U.S.C. §1342(l)(2) and §1362(24), EPA cannot require a permit for discharges of storm water from "field activities or operations associated with {oil and gas} exploration, production, processing, or treatment operations, or transmission facilities, including activities necessary to prepare a site for drilling and for the movement and placement of drilling equipment, whether or not such field activities or operations may be considered to be construction activities" unless the discharge is contaminated by contact with any overburden, raw material, intermediate product, finished product, byproduct, or waste product located on the site of the facility. Under §3.8 of this title (relating to Water Protection), the RRC prohibits operators from causing or allowing pollution of surface or subsurface water. Operators are encouraged to implement and maintain BMPs to minimize discharges of pollutants, including sediment, in storm water during construction activities to help ensure protection of surface water quality during storm events.

(III) Municipal storm water discharges. Storm water discharges from facilities regulated by the RRC located within an MS4 are not regulated by the TCEQ. However, a municipality may regulate storm water discharges from RRC sites into their MS4.

(IV) Combined storm water. Except with regard to storage of oil, when a portion of a site is regulated by the RRC and the EPA, and a portion of a site is regulated by the TCEQ, storm water authorization must be obtained from the EPA and the RRC, as applicable, for the portion(s) of the site under RRC jurisdiction and from the TCEQ for the TCEQ regulated portion(s) of the site. Discharge of storm water from a terminal facility where crude oil is stored prior to refining and at which refined products are stored solely for use at the facility is under the jurisdiction of the RRC.

(iii) State water quality certification. The RRC performs state water quality certifications, as authorized by the Clean Water Act (CWA) Section 401 (33 U.S.C. Section 1341) for activities that require a federal license or permit and that may result in any discharge to waters of the United States for those activities regulated by the RRC.

(C) Injection wells. The RRC has jurisdiction over the drilling, construction, operation, and closure of the following injection wells.

(i) Disposal wells. The RRC has jurisdiction under Texas Water Code, Chapter 27, over injection wells used to dispose of oil and gas waste. Texas Water Code, Chapter 27, defines "oil and gas waste" to mean "waste arising out of or incidental to drilling for or producing of oil, gas, or geothermal resources, waste arising out of or incidental to the underground storage of hydrocarbons other than storage in artificial tanks or containers, or waste arising out of or incidental to the operation of gasoline plants, natural gas processing plants, or pressure maintenance or repressurizing plants. The term includes but is not limited to salt water, brine, sludge, drilling mud, and other liquid or semi-liquid waste material." The term "waste arising out of or incidental to drilling for or producing of oil, gas, or geothermal resources" includes waste associated with transportation of crude oil or natural gas by pipeline pursuant to Texas Natural Resources Code, §91.101.

(ii) Enhanced recovery wells. The RRC has jurisdiction over wells into which fluids are injected for enhanced recovery of oil or natural gas.

(iii) Brine mining. Under Texas Water Code, §27.036, the RRC has jurisdiction over brine mining and may issue permits for injection wells.

(iv) Geologic storage of carbon dioxide. Under Texas Water Code, §27.011 and §27.041, and subject to the review of the legislature based on the recommendations made in the preliminary report described by Section 10, Senate Bill No. 1387, Acts of the 81st Legislature, Regular Session (2009), the RRC has jurisdiction over geologic storage of carbon dioxide in, and the injection of carbon dioxide into, a reservoir that is initially or may be productive of oil, gas, or geothermal resources or a saline formation directly above or below that reservoir and over a well used for such injection purposes regardless of whether the well was initially completed for that purpose or was initially completed for another purpose and converted.

(v) Hydrocarbon storage. The RRC has jurisdiction over wells into which fluids are injected for storage of hydrocarbons that are liquid at standard temperature and pressure.

(vi) Geothermal energy. Under Texas Natural Resources Code, Chapter 141, the RRC has jurisdiction over injection wells for the exploration, development, and production of geothermal energy and associated resources.

(vii) In situ tar sands. Under Texas Water Code, §27.035, the RRC has jurisdiction over the in situ recovery of tar sands and may issue permits for injection wells used for the in situ recovery of tar sands.

(c) Definition of hazardous waste.

(1) Under the Texas Health and Safety Code, §361.003(12), a "hazardous waste" subject to the jurisdiction of the TCEQ is defined as "solid waste identified or listed as a hazardous waste by the administrator of the United States Environmental Protection Agency under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, as amended (42 U.S.C. §6901, et seq.)." Similarly, under Texas Natural Resources Code, §91.601(1), "oil and gas hazardous waste" subject to the jurisdiction of the RRC is defined as an "oil and gas waste that is a hazardous waste as defined by the administrator of the United States Environmental Protection Agency under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976 (42 U.S.C. §§6901, et seq.)."

(2) Federal regulations adopted under authority of the federal Solid Waste Disposal Act, as amended by RCRA, exempt from regulation as hazardous waste certain oil and gas wastes. Under 40 Code of Federal Regulations (CFR) §261.4(b)(5), "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy" are described as wastes that are exempt from federal hazardous waste regulations.

(3) A partial list of wastes associated with oil, gas, and geothermal exploration, development, and production that are considered exempt from hazardous waste regulation under RCRA can be found in EPA's "Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes," 53 FedReg 25,446 (July 6, 1988). A further explanation of the exemption can be found in the "Clarification of the Regulatory Determination for Wastes from the Exploration, Development and Production of Crude Oil, Natural Gas and Geothermal Energy, " 58 FedReg 15,284 (March 22, 1993). The exemption codified at 40 CFR §261.4(b)(5) and discussed in the Regulatory Determination has been, and may continue to be, clarified in subsequent guidance issued by the EPA.

(d) Jurisdiction over waste from specific activities.

(1) Drilling, operation, and plugging of wells associated with the exploration, development, or production of oil, gas, or geothermal resources. Wells associated with the exploration, development, or production of oil, gas, or geothermal resources include exploratory wells, cathodic protection holes, core holes, oil wells, gas wells, geothermal resource wells, fluid injection wells used for secondary or enhanced recovery of oil or gas, oil and gas waste disposal wells, and injection water source wells. Several types of waste materials can be generated during the drilling, operation, and plugging of these wells. These waste materials include drilling fluids (including water-based and oil-based fluids), cuttings, produced water, produced sand, waste hydrocarbons (including used oil), fracturing fluids, spent acid, workover fluids, treating chemicals (including scale inhibitors, emulsion breakers, paraffin inhibitors, and surfactants), waste cement, filters (including used oil filters), domestic sewage (including waterborne human waste and waste from activities such as bathing and food preparation), and trash (including inert waste, barrels, dope cans, oily rags, mud sacks, and garbage). Generally, these wastes, whether disposed of by discharge, landfill, land farm, evaporation, or injection, are subject to the jurisdiction of the RRC. Wastes from oil, gas, and geothermal exploration activities subject to regulation by the RRC when those wastes are to be processed, treated, or disposed of at a solid waste management facility authorized by the

TCEQ under 30 TAC Chapter 330 are, as defined in 30 TAC §330.3(148) (relating to Definitions), "special wastes."

(2) Field treatment of produced fluids. Oil, gas, and water produced from oil, gas, or geothermal resource wells may be treated in the field in facilities such as separators, skimmers, heater treaters, dehydrators, and sweetening units. Waste that results from the field treatment of oil and gas include waste hydrocarbons (including used oil), produced water, hydrogen sulfide scavengers, dehydration wastes, treating and cleaning chemicals, filters (including used oil filters), asbestos insulation, domestic sewage, and trash are subject to the jurisdiction of the RRC.

(3) Storage of oil.

(A) Tank bottoms and other wastes from the storage of crude oil (whether foreign or domestic) before it enters the refinery are under the jurisdiction of the RRC. In addition, waste resulting from storage of crude oil at refineries is subject to the jurisdiction of the TCEQ.

(B) Wastes generated from storage tanks that are part of the refinery and wastes resulting from the wholesale and retail marketing of refined products are subject to the jurisdiction of the TCEQ.

(4) Underground hydrocarbon storage. The disposal of wastes, including saltwater, resulting from the construction, creation, operation, maintenance, closure, or abandonment of an "underground hydrocarbon storage facility" is subject to the jurisdiction of the RRC, provided the terms "hydrocarbons" and "underground hydrocarbon storage facility" have the meanings set out in Texas Natural Resources Code, §91.201.

(5) Underground natural gas storage. The disposal of wastes resulting from the construction, operation, or abandonment of an "underground natural gas storage facility" is subject to the jurisdiction of the RRC, provided that the terms "natural gas" and "storage facility" have the meanings set out in Texas Natural Resources Code, §91.173.

(6) Transportation of crude oil or natural gas.

(A) Jurisdiction over pipeline-related activities. The RRC has jurisdiction over matters related to pipeline safety for pipelines in Texas, as referenced in §8.1 of this title (relating to General Applicability and Standards) pursuant to Chapter 121 of the Texas Utilities Code and Chapter 117 of the Texas Natural Resources Code. The RRC has jurisdiction over spill response and remediation of releases from pipelines transporting crude oil, natural gas, and condensate that originate from exploration and production facilities to the refinery gate. The RRC has jurisdiction over waste generated by construction and operation of pipelines used to transport crude oil, natural gas, and condensate on an oil and gas lease, and from exploration and production facilities to the refinery gate. The RRC is responsible for water quality certification issues related to construction and operation of pipelines used to transport crude oil, natural gas, and condensate on an oil and gas lease, and from exploration and production facilities to the refinery gate. The RRC has jurisdiction over waste generated by construction and operation of pipelines transporting carbon dioxide.

(B) Crude oil and natural gas are transported by railcars, tank trucks, barges, tankers, and pipelines. The RRC has jurisdiction over waste from the transportation of crude oil by pipeline, regardless of the crude oil source (foreign or domestic) prior to arrival at a refinery. The RRC also has jurisdiction over waste from the transportation by pipeline of natural gas, including natural gas liquids, prior to the use of the natural gas in any manufacturing process or as a residential or industrial fuel. The transportation wastes subject to the jurisdiction of the RRC include wastes from pipeline compressor or pressure stations and wastes from pipeline hydrostatic pressure tests and other pipeline operations. These wastes include waste hydrocarbons (including used oil), treating and cleaning chemicals, filters (including used oil filters), scraper trap sludge, trash, domestic sewage, wastes contaminated with polychlorinated biphenyls (PCBs) (including transformers, capacitors, ballasts, and soils), soils contaminated with mercury from leaking mercury meters, asbestos insulation, transite pipe, and hydrostatic test waters.

(C) The TCEQ has jurisdiction over waste from transportation of refined products by pipeline.

(D) The TCEQ also has jurisdiction over wastes associated with transportation of crude oil and natural gas, including natural gas liquids, by railcar, tank truck, barge, or tanker.

(7) Reclamation plants.

(A) The RRC has jurisdiction over wastes from reclamation plants that process wastes from activities associated with the exploration, development, or production of oil, gas, or geothermal resources, such as lease tank bottoms. Waste management activities of reclamation plants for other wastes are subject to the jurisdiction of the TCEQ.

(B) The RRC has jurisdiction over the conservation and prevention of waste of crude oil and therefore must approve all movements of crude oil-containing materials to reclamation plants. The applicable statute and regulations consist primarily of reporting requirements for accounting purposes.

(8) Refining of oil.

(A) The management of wastes resulting from oil refining operations, including spent caustics, spent catalysts, still bottoms or tars, and American Petroleum Institute (API) separator sludges, is subject to the jurisdiction of the TCEQ. The processing of light ends from the distillation and cracking of crude oil or crude oil products is considered to be a refining operation. The term "refining" does not include the processing of natural gas or natural gas liquids.

(B) The RRC has jurisdiction over refining activities for the conservation and the prevention of waste of crude oil. The RRC requires that all crude oil streams into or out of a refinery be reported for accounting purposes. In addition, the RRC requires that materials recycled and used as a fuel, such as still bottoms or waste crude oil, be reported.

(9) Natural gas or natural gas liquids processing plants (including gas fractionation facilities) and pressure maintenance or repressurizing plants. Wastes resulting from activities associated with these facilities include produced water, cooling tower water, sulfur bead, sulfides, spent caustics, sweetening agents, spent catalyst, waste hydrocarbons (including used oil), asbestos insulation, wastes contaminated with PCBs (including transformers, capacitors, ballasts, and soils), treating and cleaning chemicals, filters, trash, domestic sewage, and dehydration materials. These wastes are subject to the jurisdiction of the RRC under Texas Natural Resources Code, §1.101. Disposal of waste from activities associated with natural gas or natural gas liquids processing plants (including gas fractionation facilities), and pressure maintenance or repressurizing plants by injection is subject to the jurisdiction of the RRC under Texas Water Code, Chapter 27. However, until delegation of authority under RCRA to the RRC, the TCEQ shall have jurisdiction over wastes resulting from these activities that are not exempt from federal hazardous waste regulation under RCRA and that are considered hazardous under applicable federal rules.

(10) Manufacturing processes.

(A) Wastes that result from the use of natural gas, natural gas liquids, or products refined from crude oil in any manufacturing process, such as the production of petrochemicals or plastics, or from the manufacture of carbon black, are industrial wastes subject to the jurisdiction of the TCEQ. The term "manufacturing process" does not include the processing (including fractionation) of natural gas or natural gas liquids at natural gas or natural gas liquids processing plants.

(B) The RRC has jurisdiction under Texas Natural Resources Code, Chapter 87, to regulate the use of natural gas in the production of carbon black.

(C) Biofuels. The TCEQ has jurisdiction over wastes associated with the manufacturing of biofuels and biodiesel. TCEQ Regulatory Guidance Document RG-462 contains additional information regarding biodiesel manufacturing in the state of Texas.

(11) Commercial service company facilities and training facilities.

(A) The TCEQ has jurisdiction over wastes generated at facilities, other than actual exploration, development, or production sites (field sites), where oil and gas industry workers are trained. In addition, the TCEQ has jurisdiction over wastes generated at facilities where materials, processes, and equipment associated with oil and gas industry operations are researched, developed, designed, and manufactured. However, wastes generated from tests of materials, processes, and equipment at field sites are under the jurisdiction of the RRC.

(B) The TCEQ also has jurisdiction over waste generated at commercial service company facilities operated by persons providing equipment, materials, or services (such as drilling and work over rig rental and tank rental; equipment repair; drilling fluid supply; and acidizing, fracturing, and cementing services) to the oil and gas industry. These wastes include the following wastes when they are generated at commercial service company facilities: empty sacks, containers, and drums; drum, tank, and truck rinsate; sandblast media; painting wastes; spent solvents; spilled chemicals; waste motor oil; and unused fracturing and acidizing fluids.

(C) The term "commercial service company facility" does not include a station facility such as a warehouse, pipeyard, or equipment storage facility belonging to an oil and gas operator and used solely for the support of that operator's own activities associated with the exploration, development, or production activities.

(D) Notwithstanding subparagraphs (A) - (C) of this paragraph, the RRC has jurisdiction over disposal of oil and gas wastes, such as waste drilling fluids and NORM-contaminated pipe scale, in volumes greater than the incidental volumes usually received at such facilities, that are managed at commercial service company facilities.

(E) The RRC also has jurisdiction over wastes such as vacuum truck rinsate and tank rinsate generated at facilities operated by oil and gas waste haulers permitted by the RRC pursuant to §3.8(f) of this title (relating to Water Protection).

(12) Mobile offshore drilling units (MODUs). MODUs are vessels capable of engaging in drilling operations for exploring or exploiting subsea oil, gas, or mineral resources.

(A) The RRC and, where applicable, the EPA, the U.S. Coast Guard, or the Texas General Land Office (GLO), have jurisdiction over discharges from an MODU when the unit is being used in connection with activities associated with the exploration, development, or production of oil or gas or geothermal resources, except that upon delegation to the TCEQ of NPDES authority for discharges into surface water in the state of produced water, hydrostatic test water, and gas plant effluent resulting from the activities described in Texas Water Code, §26.131(a), the TCEQ shall assume RRC's authority under this subsection.

(B) The TCEQ and, where applicable, the EPA, the U.S. Coast Guard, or the GLO, have jurisdiction over discharges from an MODU when the unit is being serviced at a maintenance facility.

(C) Where applicable, the EPA, the U.S. Coast Guard, or the GLO has jurisdiction over discharges from an MODU during transportation from shore to exploration, development or production site, transportation between sites, and transportation to a maintenance facility.

(e) Interagency activities.

(1) Recycling and pollution prevention.

(A) The TCEQ and the RRC encourage generators to eliminate pollution at the source and recycle whenever possible to avoid disposal of wastes. Questions regarding source reduction and recycling may be directed to the TCEQ External Relations Division, or to the RRC. The TCEQ may require generators to explore source reduction and recycling alternatives prior to authorizing disposal of any waste under the jurisdiction of the RRC at a facility regulated by the TCEQ; similarly, the RRC may explore source reduction and recycling alternatives prior to authorizing disposal of any waste under the jurisdiction of the TCEQ at a facility regulated by the RRC.

(B) The TCEQ External Relations Division and the RRC will coordinate as necessary to maintain a working relationship to enhance the efforts to share information and use resources more efficiently. The TCEQ External Relations Division will make the proper TCEQ personnel aware of the services offered by the RRC, share information with the RRC to maximize services to oil and gas operators, and advise oil and gas operators of RRC services. The RRC will make the proper RRC personnel aware of the services offered by the TCEQ External Relations Division, share information with the TCEQ External Relations Division to maximize services to industrial operators, and advise industrial operators of the TCEQ External Relations Division services.

(2) Treatment of wastes under RRC jurisdiction at facilities authorized by the TCEQ under 30 TAC Chapter 334, Subchapter K, (relating to Storage, Treatment, and Reuse Procedures for Petroleum-Substance Contaminated Soil).

(A) Soils contaminated with constituents that are physically and chemically similar to those normally found in soils at leaking underground petroleum storage tanks from generators under the jurisdiction of the RRC are eligible for treatment at TCEQ regulated soil treatment facilities once alternatives for recycling and source reduction have been explored. For the purpose of this provision, soils containing petroleum substance(s) as defined in 30 TAC §334.481 (relating to Definitions) are considered to be similar, but drilling muds, acids, or other chemicals used in oil and gas activities are not considered similar. Generators under the jurisdiction of the RRC must meet the same requirements as generators under the jurisdiction of the TCEQ when sending their petroleum contaminated soils to soil treatment facilities under TCEQ jurisdiction. Those requirements are in 30 TAC §334.496 (relating to Shipping Procedures Applicable to Generators of Petroleum-Substance Waste), except subsection (c) which is not applicable, and 30 TAC §334.497 (relating to Recordkeeping and Reporting Procedures Applicable to Generators). RRC generators with questions on these requirements should contact the TCEQ. (B) Generators under RRC jurisdiction should also be aware that TCEQ regulated soil treatment facilities are required by 30 TAC §334.499 (relating to Shipping Requirements Applicable to Owners or Operators of Storage, Treatment, or Disposal Facilities) to maintain documentation on the soil sampling and analytical methods, chain-of-custody, and all analytical results for the soil received at the facility and transported off-site or reused on-site.

(C) The RRC must specifically authorize management of contaminated soils under its jurisdiction at facilities authorized by the TCEQ under 30 TAC Chapter 334, Subchapter K. The RRC may grant such authorizations by rule, or on an individual basis through permits or other written authorizations.

(D) All waste, including treated waste, subject to the jurisdiction of the RRC and managed at facilities authorized by the TCEQ under 30 TAC Chapter 334, Subchapter K will remain subject to the jurisdiction of the RRC. Such materials will be subject to RRC regulations regarding final reuse, recycling, or disposal.

(E) TCEQ waste codes and registration numbers are not required for management of wastes under the jurisdiction of the RRC at facilities authorized by the TCEQ under 30 TAC Chapter 334, Subchapter K.

(3) Processing, treatment, and disposal of wastes under RRC jurisdiction at facilities authorized by the TCEQ.

(A) As provided in this paragraph, waste materials subject to the jurisdiction of the RRC may be managed at solid waste facilities under the jurisdiction of the TCEQ once alternatives for recycling and source reduction have been explored. The RRC must specifically authorize management of wastes under its jurisdiction at facilities regulated by the TCEQ. The RRC may grant such authorizations by rule, or on an individual basis through permits or other written authorizations. In addition, except as provided in subparagraph (B) of this paragraph, the concurrence of the TCEQ is required to manage "special waste" under the jurisdiction of the RRC at a facility regulated by the TCEQ. The TCEQ's concurrence may be subject to specified conditions.

(B) A facility under the jurisdiction of the TCEQ may accept, without further individual concurrence, waste under the jurisdiction of the RRC if that facility is permitted or otherwise authorized to accept that particular type of waste. The phrase "that type of waste" does not specifically refer to waste under the jurisdiction of the RRC, but rather to the waste's physical and chemical characteristics. Management and disposal of waste under the jurisdiction of the RRC is subject to TCEQ's rules governing both special waste and industrial waste.

(C) If the TCEQ regulated facility receiving the waste does not have approval to accept the waste included in its permit or other authorization, individual written concurrences from the TCEQ shall be required to manage wastes under the jurisdiction of the RRC at TCEQ regulated facilities. Recommendations for the management of special wastes associated with the exploration, development, or production of oil, gas, or geothermal resources are found in TCEQ Regulatory Guidance document RG-3.

(This is required only if the TCEQ regulated facility receiving the waste does not have approval to accept the waste included in its permit or other authorization provided by the TCEQ.) To obtain an individual concurrence, the waste generator must provide to the TCEQ sufficient information to allow the concurrence determination to be made, including the identity of the proposed waste management facility, the process generating the waste, the quantity of waste, and the physical and chemical nature of the waste involved (using process knowledge and/or laboratory analysis as defined in 30 TAC Chapter 335, Subchapter R (relating to Waste Classification)). In obtaining TCEQ approval, generators may use their existing knowledge about the process or materials entering it to characterize their wastes. Material Safety Data Sheets, manufacturer's literature, and other documentation generated in conjunction with a particular process may be used. Process knowledge must be documented and submitted with the request for approval.

(D) Domestic septage collected from portable toilets at facilities subject to RRC jurisdiction that is not mixed with other waste materials may be managed at a facility permitted by the TCEQ for disposal, incineration, or land application for beneficial use of such domestic septage waste without specific authorization from the TCEQ or the RRC. Waste sludge subject to the jurisdiction of the RRC may not be applied to the land at a facility permitted by the TCEQ for the beneficial use of sewage sludge or water treatment sludge.

(E) TCEQ waste codes and registration numbers are not required for management of wastes under the jurisdiction of the RRC at facilities under the jurisdiction of the TCEQ. If a receiving facility requires a TCEQ waste code for waste under the jurisdiction of the RRC, a code consisting of the following may be provided:

(i) the sequence number "RRCT";

(ii) the appropriate form code, as specified in 30 TAC Chapter 335, Subchapter R, §335.521, Appendix 3 (relating to Appendices); and

(iii) the waste classification code "H" if the waste is a hazardous oil and gas waste, or "R" if the waste is a nonhazardous oil and gas waste.

(F) If a facility requests or requires a TCEQ waste generator registration number for wastes under the jurisdiction of the RRC, the registration number "XXXRC" may be provided.

(G) Wastes that are under the jurisdiction of the RRC need not be reported to the TCEQ.

(4) Management of nonhazardous wastes under TCEQ jurisdiction at facilities regulated by the RRC.

(A) Once alternatives for recycling and source reduction have been explored, and with prior authorization from the RRC, the following nonhazardous wastes subject to the jurisdiction of the TCEQ may be disposed of, other than by injection into a Class II well, at a facility regulated by the RRC; bioremediated at a facility regulated by the RRC (prior to reuse, recycling, or disposal); or reclaimed at a crude oil reclamation facility regulated by the RRC: nonhazardous wastes that are chemically and physically similar to oil and gas wastes, but excluding soils, media, debris, sorbent pads, and other clean-up materials that are contaminated with refined petroleum products.

(B) To obtain an individual authorization from the RRC, the waste generator must provide the following information, in writing, to the RRC: the identity of the proposed waste management facility, the quantity of waste involved, a hazardous waste determination that addresses the process generating the waste and the physical and chemical nature of the waste, and any other information that the RRC may require. As appropriate, the RRC shall reevaluate any authorization issued pursuant to this paragraph.

(C) Once alternatives for recycling and source reduction have been explored, and subject to the RRC's individual authorization, the following wastes under the jurisdiction of the TCEQ are authorized without further TCEQ approval to be disposed of at a facility regulated by the RRC, bioremediated at a facility regulated by the RRC, or reclaimed at a crude oil reclamation facility regulated by the RRC: nonhazardous bottoms from tanks used only for crude oil storage; unused and/or reconditioned drilling and completion/workover wastes from commercial service company facilities; used and/or unused drilling and completion/workover wastes generated at facilities where workers in the oil and gas exploration, development, and production industry are trained; used and/or unused drilling and completion/workover wastes generated at facilities where materials, processes, and equipment associated with oil and gas exploration, development, and production operations are researched, developed, designed, and manufactured; unless other provisions are made in the underground injection well permit used and/or unused drilling and completion wastes (but not workover wastes) generated in connection with the drilling and completion of Class I, III, and V injection wells; wastes (such as contaminated soils, media, debris, sorbent pads, and other cleanup materials) associated with spills of crude oil and natural gas liquids if such wastes are under the jurisdiction of the TCEQ; and sludges from washout pits at commercial service company facilities.

(D) Under Texas Water Code, §27.0511(g), a TCEQ permit is required for injection of industrial or municipal waste as an injection fluid for enhanced recovery purposes. However, under §27.0511(h), the RRC may authorize a person to use nonhazardous brine from a desalination operation or nonhazardous drinking water treatment residuals as an injection fluid for enhanced recovery purposes without obtaining a permit from the TCEQ. The use or disposal of radioactive material under this subparagraph is subject to the applicable requirements of Texas Health and Safety Code, Chapter 401.

(E) Under Texas Water Code, §27.026, by individual permit, general permit, or rule, the TCEQ may designate a Class II disposal well that has an RRC permit as a Class V disposal well authorized to dispose by injection nonhazardous brine from a desalination operation and nonhazardous drinking water treatment residuals under the jurisdiction of the TCEQ. The operator of a permitted Class II disposal well seeking a Class V authorization must apply to TCEQ and obtain a Class V authorization prior to disposal of nonhazardous brine from a desalination operation or nonhazardous drinking water treatment residuals. A permitted Class II disposal well that has obtained a Class V authorization from TCEQ under Texas Water Code, §27.026, remains subject to the regulatory requirements of both the RRC and the TCEQ. Nonhazardous brine from a desalination operation and nonhazardous drinking water treatment residuals to be disposed by injection in a permitted Class II disposal well authorized by TCEQ as a Class V injection well remain subject to the requirements of the Texas Health and Safety Code, the Texas Water Code, and the TCEQ's rules. The RRC and the TCEQ may impose additional requirements or conditions to address the dual injection activity under Texas Water Code, §27.026.

(5) Drilling in landfills. The TCEQ will notify the Oil and Gas Division of the RRC and the landfill owner at the time a drilling application is submitted if an operator proposes to drill a well through a landfill regulated by the TCEQ. The RRC and the TCEQ will cooperate and coordinate with one another in advising the appropriate parties of measures necessary to reduce the potential for the landfill contents to cause groundwater contamination as a result of landfill disturbance associated with drilling operations. The TCEQ requires prior written approval before drilling of any test borings through previously deposited municipal solid waste under 30 TAC §330.15 (relating to General Prohibitions), and before borings or other penetration of the final cover of a closed municipal solid waste landfill under 30 TAC §330.955 (relating to Miscellaneous). The installation of landfill gas recovery wells for the recovery and beneficial reuse of landfill gas is under the jurisdiction of the TCEQ in accordance with 30 TAC Chapter 330, Subchapter I (relating to Landfill Gas Management). Modification of an active or a closed solid waste management unit, corrective action management unit, hazardous waste landfill cell, or industrial waste landfill cell by drilling or penetrating into or through deposited waste may require prior written approval from TCEQ. Such approval may require a new authorization from TCEQ or modification or amendment of an existing TCEQ authorization.

(6) Coordination of actions and cooperative sharing of information.

(A) In the event that a generator or transporter disposes, without proper authorization, of wastes regulated by the TCEQ at a facility permitted by the RRC, the TCEQ is responsible for enforcement actions against the generator or transporter, and the RRC is responsible for enforcement actions against the disposal facility. In the event that a generator or transporter disposes, without proper authorization, of wastes regulated by the RRC at a facility permitted by the TCEQ, the RRC is responsible for enforcement actions against the generator or transporter, and the TCEQ is responsible for enforcement actions against the disposal facility.

(B) The TCEQ and the RRC agree to cooperate with one another by sharing information. Employees of either agency who receive a complaint or discover, in the course of their official duties, information that indicates a violation of a statute, regulation, order, or permit pertaining to wastes under the jurisdiction of the other agency, will notify the other agency. In addition, to facilitate enforcement actions, each agency will share information in its possession with the other agency if requested by the other agency to do so.

(C) The TCEQ and the RRC agree to work together at allocating respective responsibilities. To the extent that jurisdiction is indeterminate or has yet to be determined, the TCEQ and the RRC agree to share information and take appropriate investigative steps to assess jurisdiction.

(D) For items not covered by statute or rule, the TCEQ and the RRC will collaborate to determine respective responsibilities for each issue, project, or project type.

(E) The staff of the RRC and the TCEQ shall coordinate as necessary to attempt to resolve any disputes regarding interpretation of this MOU and disputes regarding definitions and terms of art.

(7) Groundwater.

(A) Notice of groundwater contamination. Under Texas Water Code, §26.408, effective September 1, 2003, the RRC must submit a written notice to the TCEQ of any documented cases of groundwater contamination that may affect a drinking water well. (B) Groundwater protection letters. The RRC provides letters of recommendation concerning groundwater protection.

(i) For recommendations related to normal drilling operations, shot holes for seismic surveys, and cathodic protection wells, the RRC provides geologic interpretation identifying fresh water zones, base of usable-quality water (generally less than 3,000 mg/L total dissolved solids, but may include higher levels of total dissolved solids if identified as currently being used or identified by the Texas Water Development Board as a source of water for desalination), and include protection depths recommended by the RRC. The geological interpretation may include groundwater protection based on potential hydrological connectivity to usable-quality water.

(ii) For recommendations related to injection, the RRC provides geologic interpretation of the base of the underground source of drinking water. The term "underground source of drinking water" is defined in 40 Code of Federal Regulations §146.3 (Federal Register, Volume 46, June 24, 1980).

(8) Emergency and spill response.

(A) The TCEQ and the RRC are members of the state's Emergency Management Council. The TCEQ is the state's primary agency for emergency support during response to hazardous materials and oil spill incidents. The TCEQ is responsible for state-level coordination of assets and services, and will identify and coordinate staffing requirements appropriate to the incident to include investigative assignments for the primary and support agencies.

(B) Contaminated soil and other wastes that result from a spill must be managed in accordance with the governing statutes and regulations adopted by the agency responsible for the activity that resulted in the spill. Coordination of issues of spill notification, prevention, and response shall be addressed in the State of Texas Oil and Hazardous Substance Spill Contingency Plan and may be addressed further in a separate Memorandum of Understanding among these agencies and other appropriate state agencies.

(C) The agency (TCEQ or RRC) that has jurisdiction over the activity that resulted in the spill incident will be responsible for measures necessary to monitor, document, and remediate the incident.

(i) The TCEQ has jurisdiction over certain inland oil spills, all hazardous-substance spills, and spills of other substances that may cause pollution.

(ii) The RRC has jurisdiction over spills or discharges from activities associated with the exploration, development, or production of crude oil, gas, and geothermal resources, and discharges from brine mining or surface mining.

(D) If TCEQ or RRC field personnel receive spill notifications or reports documenting improperly managed waste or contaminated environmental media resulting from a spill or discharge that is under the jurisdiction of the other agency, they shall refer the issue to the other agency. The agency that has jurisdiction over the activity that resulted in the improperly managed waste, spill, discharge, or contaminated environmental media will be responsible for measures necessary to monitor, document, and remediate the incident.

(9) Anthropogenic carbon dioxide storage. In determining the proper permitting agency in regard to a particular permit application for a carbon dioxide geologic storage project, the TCEQ and the RRC will coordinate by any appropriate means to review proposed locations, geologic settings, reservoir data, and other jurisdictional criteria specified in Texas Water Code, §27.041.

(f) Radioactive material.

(1) Radioactive substances. Under the Texas Health and Safety Code, §401.011, the TCEQ has jurisdiction to regulate and license:

(A) the disposal of radioactive substances;

(B) the processing or storage of low-level radioactive waste or NORM waste from other persons, except oil and gas NORM waste;

(C) the recovery or processing of source material;

(D) the processing of by-product material as defined by Texas Health and Safety Code, §401.003(3)(B); and

(E) sites for the disposal of low-level radioactive waste, by-product material, or NORM waste.

(2) NORM waste.

(A) Under Texas Health and Safety Code, §401.415, the RRC has jurisdiction over the disposal of NORM waste that constitutes, is contained in, or has contaminated oil and gas waste. This waste material is called "oil and gas NORM waste." Oil and gas NORM waste may be generated in connection with the exploration, development, or production of oil or gas.

(B) Under Texas Health and Safety Code, §401.412, the TCEQ has jurisdiction over the disposal of NORM that is not oil and gas NORM waste.

(C) The term "disposal" does not include receipt, possession, use, processing, transfer, transport, storage, or commercial distribution of radioactive materials, including NORM. These non-disposal activities are under the jurisdiction of the Texas Department of State Health Services under Texas Health and Safety Code, §401.011(a).

(3) Drinking water residuals. A person licensed for the commercial disposal of NORM waste from public water systems may dispose of NORM waste only by injection into a Class I injection well permitted under 30 TAC Chapter 331 (relating to Underground Injection Control) that is specifically permitted for the disposal of NORM waste.

(4) Management of radioactive tracer material.

(A) Radioactive tracer material is subject to the definition of low-level radioactive waste under Texas Health and Safety Code, §401.004, and must be handled and disposed of in accordance with the rules of the TCEQ and the Department of State Health Services.

(B) Exemption. Under Texas Health and Safety Code, §401.106, the TCEQ may grant an exemption by rule from a licensing requirement if the TCEQ finds that the exemption will not constitute a significant risk to the public health and safety and the environment.

(5) Coordination with the Texas Radiation Advisory Board. The RRC and the TCEQ will consider recommendations and advice provided by the Texas Radiation Advisory Board that concern either agency's policies or programs related to the development, use, or regulation of a source of radiation. Both agencies will provide written response to the recommendations or advice provided by the advisory board.

(6) Uranium exploration and mining.

(A) Under Texas Natural Resources Code, Chapter 131, the RRC has jurisdiction over uranium exploration activities.

(B) Under Texas Natural Resources Code, Chapter 131, the RRC has jurisdiction over uranium mining, except for in situ recovery processes.

(C) Under Texas Water Code, §27.0513, the TCEQ has jurisdiction over injection wells used for uranium mining.

(D) Under Texas Health and Safety Code, §401.2625, the TCEQ has jurisdiction over the licensing of source material recovery and processing or for storage, processing, or disposal of by-product material.

(g) Effective date. This Memorandum of Understanding, as of its July 15, 2020, effective date, shall supersede the prior Memorandum of Understanding among the agencies, dated May 1, 2012.

Source Note: The provisions of this §3.30 adopted to be effective May 31, 1998, 23 TexReg 5427; amended to be effective August 25, 2003, 28 TexReg 6816; amended to be effective August 30, 2010, 35 TexReg 7728; amended to be effective May 1, 2012, 37 TexReg 2385; amended to be effective July 15, 2020, 45 TexReg 4503

Appendix 10: 2003 EPA/ Industry MOA Concerning Diesel Use in Hydraulic Fracturing

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

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

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 DOE to inform them of progress in implementing the MOA and to solicit their cooperation, as appropriate, in implementation of the MOA.

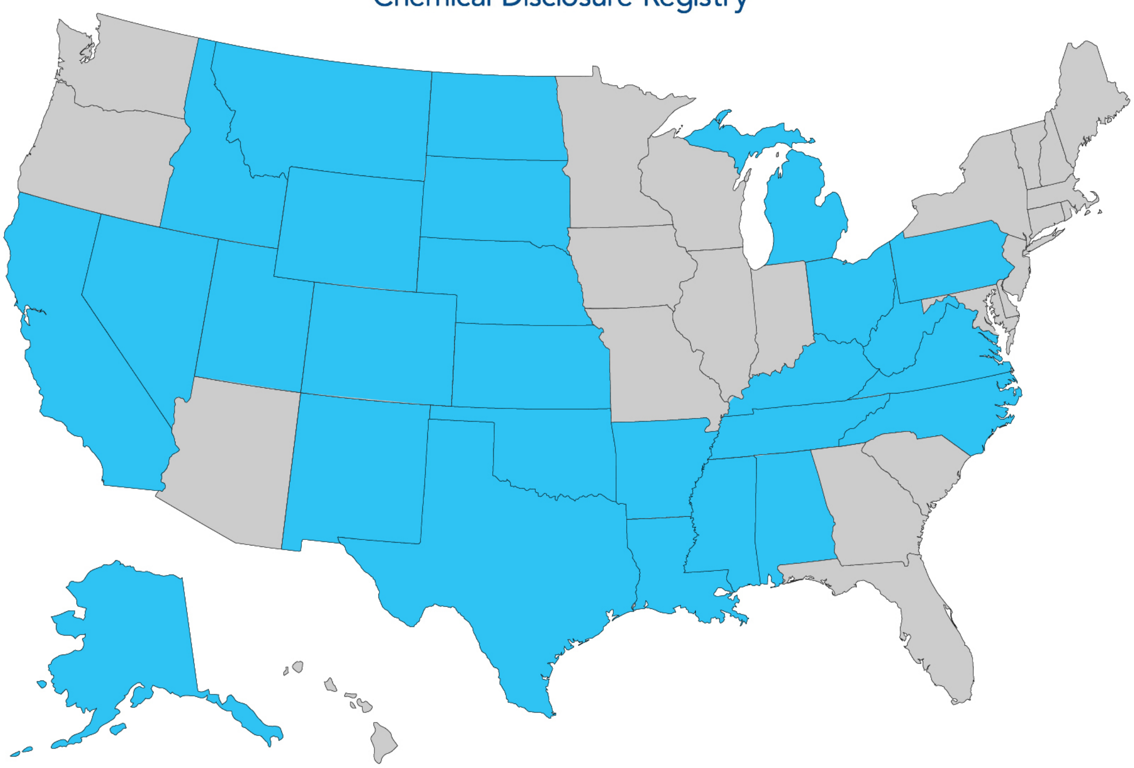
C. EPA agrees to issue a final version of the draft report entitled *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs* as soon as reasonably possible.

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.

Appendix 11: Map of FracFocus Partner States, January 2021

Frac Focus
Chemical Disclosure Registry



FracFocus Partner States

Appendix 12: Map of RBDMS Partner States, October 2022