RFF REPORT

The State of State Shale Gas Regulation

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Alan Krupnick, and Hannah Wiseman

JUNE 2013

RESOURCES FOR THE FUTURE

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THE STATE OF STATE SHALE GAS REGULATION

Nathan Richardson, Madeline Gottlieb, Alan Krupnick, and Hannah Wiseman[1]

1. Introduction

Production of natural gas from deep shale deposits in the United States by way of horizontal drilling and hydraulic fracturing (fracking) has rapidly increased in recent years. This boom, along with estimates of large untapped reserves and predictions of future production increases, has led to great optimism. But many are also deeply concerned about the environmental consequences of shale gas production, including possible damage to ground and surface water, habitat destruction, and air pollution.

Balancing these risks and opportunities through regulation has been primarily the responsibility of states. The result of this balancing, as documented here, is great heterogeneity in shale gas regulation across the country. In certain respects, this should not be surprising. After all, states vary in how they regulate all sorts of markets and behaviors—states have different income tax rates, speed limits, insurance regulations, and so on.

Heterogeneity in and of itself is not good or bad. A main part of government's job is to internalize externalities, such as pollution. If the heterogeneity we observed reflects different conditions across states that lead to different levels of environmental risks, then that heterogeneity is a good thing. On the other hand, if the heterogeneity does not depend on environmental risks but is, perhaps, more dependent on politics, regulatory capture, economic concerns about jobs, or simply historical evolution or unexamined assumptions, we might question whether this heterogeneity is justified. Indeed, even if a state's regulations perfectly internalized in-state externalities, these regulations may affect the environment in neighboring or downstream states. Unless the states coordinate—or a river basin commission (RBC) has the necessary authority—a problem could still exist.

The core of this report is a catalog of a range of state regulations—25 regulatory elements in all—relevant to shale gas, across 31 states with actual or potential shale gas production. These data are an important new resource for understanding how states are managing the risks of shale gas development.

This review is broad but necessarily incomplete—fully describing even one state's shale gas-related regulations would probably take multiple volumes and would need to be updated frequently. Our primary aim is to give a broad overview of the similarities and differences among states as of March 2013—their choices about what parts of the development process to regulate, how stringently to do so, and what regulatory tools to use. In at least the first two of these respects, we found that the heterogeneity among states is great, though not necessarily unexpected. We also found a lack of

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transparency in some aspects of regulation in some states, particularly those that use a permitting process to regulate case by case, rather than published administrative rules.

For the 27 states in our study with significant gas development, we do more than simply list and describe regulations—we also provide legal and economic tools and nomenclature for comparing them and, where possible, offer and test some hypotheses for the observed heterogeneity. We selected more than 50 geological, hydrological, demographic, economic, political, environmental, and other variables that we hypothesized might be associated with the observed regulatory heterogeneity. We found some statistically significant associations, but these together can explain only a small portion of the heterogeneity we observed.[2] Some of these significant variables include the level of natural gas development (as measured by the number of wells), the share of land in a state owned by the federal government, and, for groundwater regulations, the fraction of water consumption in a state from groundwater.

These associations may give some readers partial assurance that heterogeneity is justified. They may leave others puzzled regarding the sources of heterogeneity and whether it is justified. Others may see these results as justification for opening up the largely uncoordinated set of state regulatory activities to further scrutiny and reform. And some may believe that our set of variables is too limited and inadequate as a basis for any claim. We are the first to admit that explaining why state regulations on specific regulatory elements differ is a hugely complicated task of which our analysis has only scratched the surface. Our analyses alone cannot identify all the sources of regulatory heterogeneity, much less determine the degree to which that heterogeneity is justified. But they may shift the rhetorical burden of proof onto those who claim that the status quo (however dynamic) should be accepted.

Although the regulatory data in our analysis do allow us to make some generalizations and comparisons among states, they do not make it possible to fully explain regulatory heterogeneity, to judge the quality of any state's shale gas regulations, or much less to compare states and say which are "better"—however that is defined. To do so would require data on enforcement, environmental outcomes, and regulatory costs—none of which is included in this report—as well as a more comprehensive data-gathering and modeling effort. Nevertheless, knowing what the regulations are and how they relate to each other are important first steps.

This report is structured as follows. Section 2 frames the discussion with an overview of the shale gas development boom and government's regulatory responses. Section 3 describes what we did—our methodologies and rationale for including and excluding data. Section 4 gives a general overview of our findings, including summary statistics and basic comparisons among states. Section 5, the core of the report, gives a detailed description of regulations across states for each regulatory element, with corresponding maps. In Section 6, we statistically analyze the patterns of regulatory heterogeneity that emerge. Section 7 discusses conclusions. Summary tables, extended statistical discussion, and a matrix with our full regulatory data and citations are provided in the Appendices, which can be found at www.rff.org/shalemaps.

[2] By "explain" in this sense we mean the degree to which the statistically significant associations we identify account in a statistical sense for variation in the measures of regulatory activity, not the degree to which those variables *cause* that variation. We make no claims here to have identified the causes of heterogeneity, only correlations that may be evidence of causation.

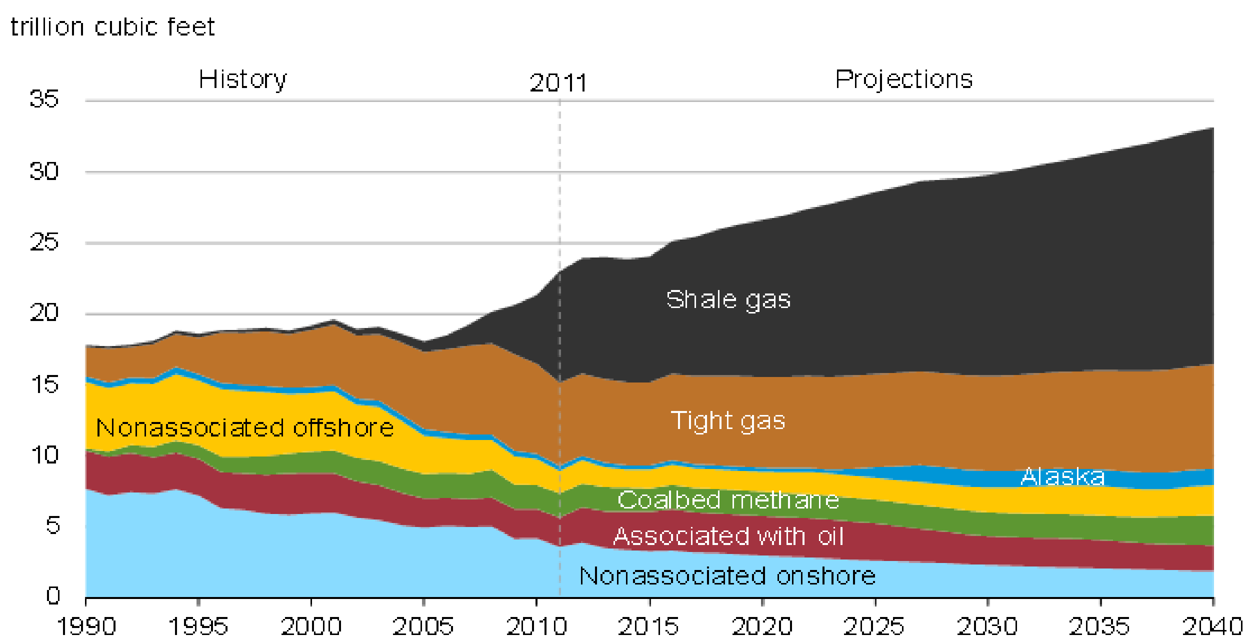
2. Shale Gas Development and Regulatory Context

2.1 The Shale Gas Boom

Knowledge about where shale gas might be found has been available for decades, but in recent years, improved technologies for exploiting these resources have made development economical, resulting in a boom in production. The key technologies are horizontal drilling, which allows each well to exploit much more of the shale layer; three-dimensional seismic imaging, which provides precise knowledge about the location and properties of the source rock; and hydraulic fracturing, which uses high-pressure fluids to physically fracture the source rock, increasing gas production.

Annual total US gas production has grown rapidly even as conventional gas production has trended downward (see Figure 1). Projections to 2035 are for more of the same. Shale gas accounted for only 1.6 percent of total US natural gas production in 2000, but this percentage had jumped to 4.1 percent by 2005 and to an astonishing 23.1 percent by 2010.

Figure 1. US Gas Production, 1990–2040 (Projected)[3]



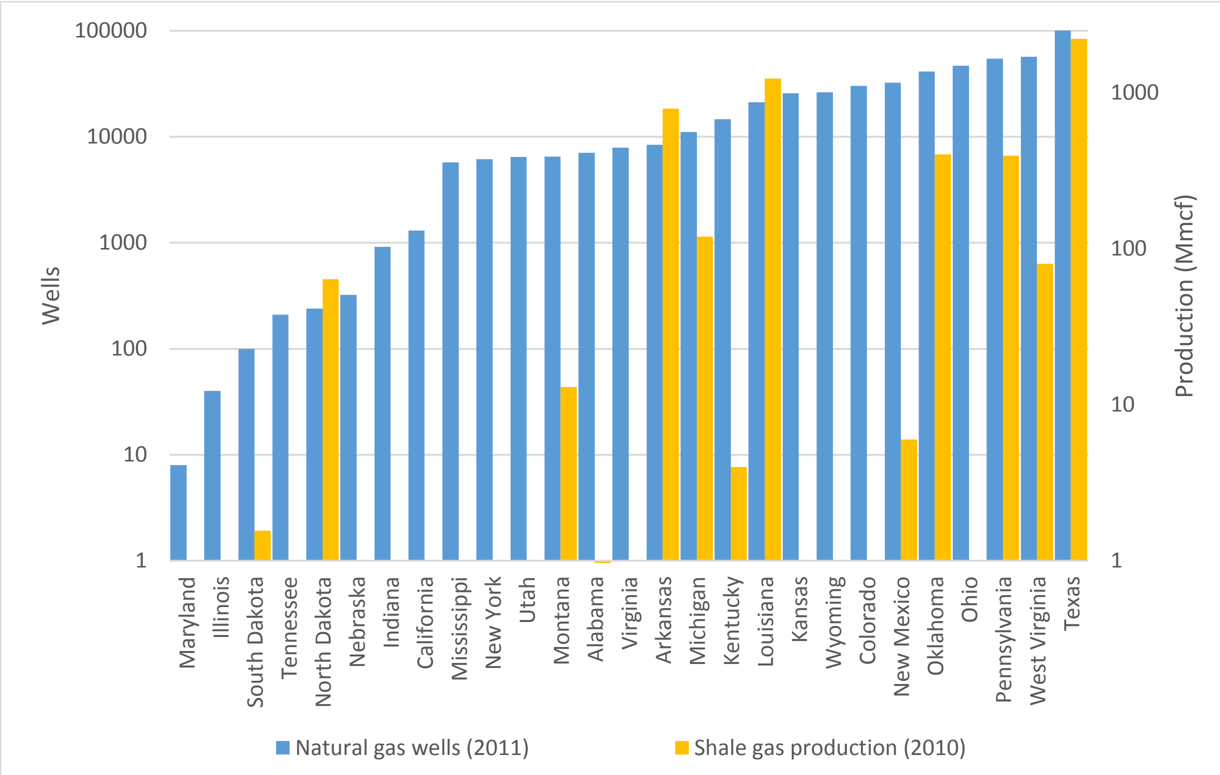
2.2 Distribution of Production Activity

The shale gas boom is a national phenomenon in that many states have development activity. Figure 2 gives a rough overview of the level of development by state (note the logarithmic scale). State-by-state data on shale gas development are limited, however. The number of unconventional wells per state is not available in government data, so Figure 2 shows the total number of natural gas wells

[3] Source: EIA (Energy Information Administration), *Annual Energy Outlook 2013 Early Release* (Washington, DC: EIA, 2012), accessed May 7, 2013, http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2013).pdf.

(conventional and unconventional) in each state. States-by-state shale gas production data are available, but only through 2010. National data (see Figure 1) indicate that shale gas production has increased significantly since then. States that had little shale production in 2010 may have since become major players.

Figure 2. Number of Natural Gas Wells and Shale Gas Production by State[4]



This rapid increase in shale gas development in recent years probably means that the degree of state experience with development activity varies greatly. Furthermore, some states have long experience with conventional oil and gas development, whereas others do not, although states are coming up to speed rapidly and participate increasingly in information-sharing forums and dialogues. At a minimum, those states with significant production in 2010 can be assumed to have at least some experience—or, more accurately given the pace of legislation, to have had an opportunity to draft and implement some regulations. This variability in states' experience nevertheless may be an important reason for regulatory differences (this hypothesis is explored in Section 6).

2.3 Environmental Risks

Shale gas development is not without risks. Critics claim that drilling and production can contaminate groundwater; release air pollution including methane, a potent greenhouse gas (GHG); pollute lakes and streams; disrupt wildlife habitats; and negatively impact local communities. There is great controversy over the significance of these risks. Other work at Resources for the Future has clarified the picture somewhat by identifying a consensus set of risks considered by different classes of

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[4] Source: EIA, *Annual Energy Outlook 2013 Early Release*.
"Number of Producing Gas Wells," EIA, April 30, 2013, accessed May 7, 2013, www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm.

stakeholders to be a high priority for industry and/or government action[5] and by examining the impact of shale gas development activity on surface water quality monitors in Pennsylvania (Olmstead et al. 2013).

Nevertheless, shale gas development remains a contentious political issue. Some states have responded by banning hydraulic fracturing or issuing moratoria. Others have moved to regulate it beyond existing oil and gas regulations that preceded the shale gas boom, and almost all stakeholders agree that effective regulation is essential to sustainable development of shale gas resources and the preservation of firms' social license to operate. It is worth noting, however, that although the shale gas boom is a new development, shale gas drilling is similar to conventional drilling in most respects. Most related environmental risks—and most of the regulations aimed at reducing these risks—are common to both conventional and unconventional drilling.

In this report, we make no effort or claim to determine the relative priority of addressing various risks related to development, or even whether given risks are sufficient to warrant regulation.[6] Instead, we aim to catalog and analyze existing regulations intended to address those risks. These regulations can be fairly taken to reflect regulators' and/or legislators' views on what risks should be regulated, and how.

2.4 Regulatory Background

Throughout our analysis, we define regulation to include any of the many regulatory tools available to states—command-and-control, case-by-case permitting, performance standards, and other tools. Although these tools differ in important ways (discussed in Section 4.2.2), all are valid forms of regulation, and none is necessarily less stringent or effective than the others.

Outside of federal lands and offshore production, mining, oil and gas drilling, and other extractive industries have historically been regulated primarily by state governments. This pattern has remained consistent throughout the shale gas boom—states remain the primary venue for most oil and gas regulation, including that for shale gas. States regulate the location and spacing of well sites, the methods of drilling, casing (lining), fracking, and plugging wells, the disposal of most oil and gas wastes, and site restoration. State common and public law governs the interpretation of lease provisions and disputes between surface and mineral owners and mineral lessees about payments and surface damage.

However, federal authority over some parts of shale gas development is significant, particularly regarding the protection of air and surface water quality, and endangered species. The federal government also plays a direct role in that it issues regulations in its capacity as a landowner—many states with shale gas deposits include large areas of federally owned land. RBCs also issue relevant regulations via the authority they have been delegated by states to protect watersheds. In some cases, municipalities, too, have an important role, placing limits on the weight of equipment on roads; requiring operators to repair road damage; taxing oil and gas operations; and additionally constraining well pad locations, drilling and fracking techniques, and waste disposal methods. See

[5] See the Resources for the Future companion report: Alan Krupnick, Hal Gordon, and Sheila Olmstead, *Pathways to Dialogue: What the Experts Say about the Environmental Risks of Shale Gas Development* (Washington, DC: Resources for the Future, 2013), accessed May 7, 2013, http://www.rff.org/centers/energy_economics_and_policy/Pages/Shale-Gas-Expert-Survey.aspx.
[6] These questions are addressed in Krupnick et al., *Pathways to Dialogue*, which describes a survey of shale gas development experts about their views on high-priority risks.

Appendix 2 for a detailed discussion of how regulatory authority is divided among levels of government.

The predominance of states in regulating shale gas development activities allows them to weigh their own trade-offs between the costs and benefits of regulation, taking into account history, geology, demographics, and other factors, as well as the public's tolerance for risk.

But the rapid expansion of shale gas development in recent years (along with tight budgets) has challenged state regulators to keep pace. Many states regulate shale gas development primarily or exclusively with older regulations written before unconventional drilling became common (though this alone does not mean that these regulations are inadequate). Rapid expansion creates a dynamic regulatory environment and may be a significant factor in observed heterogeneity among state regulations. It also means that any catalog of state regulation is only a snapshot of a moving target. The analysis of state shale gas regulation presented in this report is just such a snapshot.

3. Surveying US State Shale Gas Regulation

This section describes how the analysis was created. Section 4 gives a broad overview and analysis of findings, and Section 5 is a detailed element-by-element description of the results.

3.1 Scope

This analysis includes 31 states that have, or appear to have some potential for, shale gas development (see Map 1). Shale gas production levels vary greatly among these states—Texas alone had nearly twice the production of any other state in the most recent year for which data are available (2010).[7] In that year, the Energy Information Administration (EIA) reported shale gas production in 12 states (see Figure 2 for more detail on production by state). However, the shale gas boom has continued rapidly in the last few years, and anecdotal evidence indicates that many more states have active production.

The top five states by number of gas wells—Texas, West Virginia, Pennsylvania, Ohio, and Oklahoma—are outlined in yellow in each regulatory map (though note that this is only a very rough proxy for the number of shale gas wells or level of production). The four states without wells as of 2011 (Georgia, North Carolina, New Jersey, and Vermont) are outlined in red on each map and are excluded from our statistical analyses. These states were included in the study despite their relative (or absolute) lack of production because at least some evidence suggests potential future development (particularly in North Carolina) or industry leasing activity.[8]

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[7] "Shale Gas Production," EIA, August 2, 2012, accessed May 7, 2013, http://www.eia.gov/dnav/ng/ng_prod_shalegas_s1_a.htm.

[8] North Carolina, by some estimates, has enough shale gas potential to power the state for 40 years (Michael Futch, "The Shale Gas Boom: Energy Exploration in Carolina," *fayobserver.com*, May 22, 2011, accessed May 7, 2013, http://fayobserver.com/articles/2011/05/22/1084179?sac=home). Leases have already been offered and signed in many parts of the state, and the legislature has passed many rules pertaining to the development process (S.B. 76). Georgia was included in the survey because the state was known to have potential reserves, land had been leased and test wells were being drilled ("An Oklahoma-based company that leased 7,500 acres of land outside Dalton has two test wells in place and plans another nearby. Seventy miles away, near Cave Spring, a Texas oil, gas and development conglomerate plans a deeper well . . . Drawn by the geologic similarities embedded in the Conasauga formation, Spalvieri investigated Georgia in 2007. Within two years Buckeye and a partner had leased 7,500 acres of mineral rights from 130 landowners." Chapman, Dan. "Gas Drillers Turn to Georgia." The Atlanta Journal. Online Athens, 10 Mar. 2013.). Both New Jersey and Vermont have potential shale gas only in small areas (API, "Shale Answers," March 2013: see map on page 2, http://www.api.org/~/media/Files/Policy/Hydraulic_Fracturing/Shale-Answers-Brochure.pdf). Vermont State Geologist Lawrence Becker says "The Utica Shale in Quebec extends into Northwestern Vermont"

Some states in our analysis, such as California and North Dakota, are better known for their production of shale oil than shale gas, but all of these states have at least some gas production from shale deposits, either as a co-product with oil or independently. However, states that to the best of our knowledge have hydraulic fracturing activity and regulation only in non-shale formations, such as coalbed methane, are not included in the analysis—Idaho is one such example.

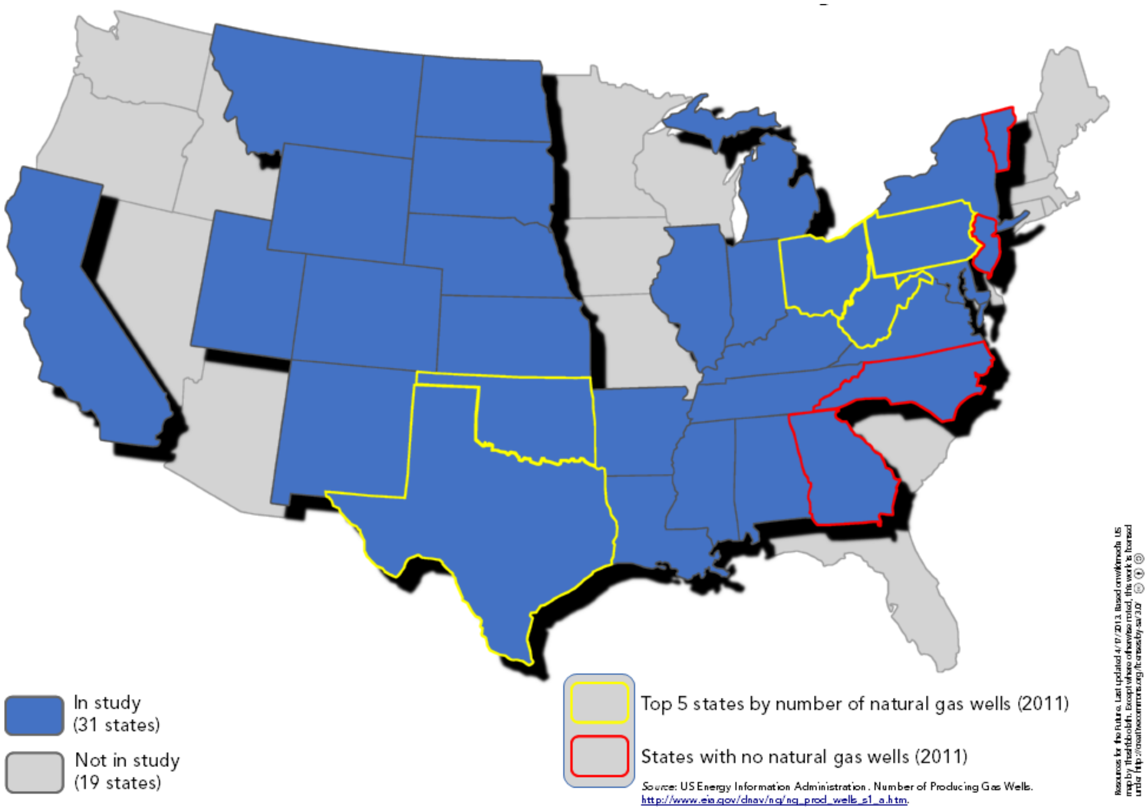
Because industry best practice guidelines may also influence operator activities, we also compared one such set of guidelines, from the American Petroleum Institute (API), to the states' regulations.[9] API's best practices are developed by industry experts in a variety of fields, including technology and operations, and are intended to serve as a guideline for industry operators in the field. According to API, the guidelines are designed to meet or exceed federal standards while remaining flexible enough to accommodate variations in state regulations and conditions.[10]

(Panebaker, Alan. "Fracking in Vermont? Probably Not." VTDigger. N.p., 6 Dec. 2011.), as shown in his presentation at the Conference of the Quebec Oil and Gas Association (Becker, Laurence, Marjorie Gale, and Jonathan Kim. Northern Vermont, Southern Quebec: Utica Shale Equivalents, Stratigraphic and Structural Relations. Publication. Waterbury, VT: Vermont Geological Survey, 2009.). Several studies, including one by the National Energy Technology Laboratory cite Marcellus shale in New Jersey, "Gross thickness of the Marcellus ranges from more than 250 ft (76m) in Northwestern Pennsylvania and New Jersey…" Hardage, Bob, Engin Alkin, Milo Backus, Michael DeAngelo, Diana Sava, Donald Wagner, and Robert Graebner. Evaluation of Fracture Systems and Stress Fields within the Marcellus Shale and Utica Shale and Characterizaiton of Associated Water-Disposal Reservoirs: Appalachian Basin. Rep. no. 08122-55. N.p.: Bureau of Economic Geology, University of Texas at Austin, 2013.).

[9] We used API Guidance Document HF1, "Hydraulic Fracturing Operations- Well Construction and Integrity Guidelines," First Edition, October 2009 (covers well construction and integrity for wells that will be fracked), API Guidance Document HF2, "Water Management Associated with Hydraulic Fracturing," First Edition, June 2010 (deals with the acquisition, use, management, treatment, and disposal of water and other fluids associated with fracking), API Guidance Document HF3, "Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing," First Edition, January 2011 (minimizes surface impacts associated with fracking, protects surface water, soil, wildlife, ecosystems, and communities, including frack fluid disclosure), and API Recommended Practice 51R, "Environmental Protection for Onshore Oil and Gas Production Operations and Leases," First Edition, July 2009 (general rules for onshore drilling including fracking deals with life cycle environmental protection practices). This is the package that API advertises as being specific to unconventional operations (American Petroleum Institute, "Overview of Industry Guidance/Best Practices on Hydraulic Fracturing (HF)," January 2012: http://www.api.org/~/media/files/policy/exploration/hydraulic_fracturing_infosheet.ashx).

[10] American Petroleum Institute, "Overview of Industry Guidance/Best Practices on Hydraulic Fracturing (HF)," January 2012: http://www.api.org/~/media/files/policy/exploration/hydraulic_fracturing_infosheet.ashx

Map 1. States Surveyed



For each of these 31 states, we surveyed laws and regulations related to 25 elements of the shale gas development process (Table 1). This set of regulatory elements is not comprehensive—not all state regulations affecting shale gas are described. The elements in the analysis were selected to give an overview of common regulations throughout the shale gas development process and are sufficient, we believe, to give an accurate general picture of the state of state regulation. It is worth reiterating here that our data do not include federal, local, or, for the most part, state-level regulation that does not apply state-wide (i.e., field-specific rules).

Table 1. Regulatory Elements Surveyed

Site selection and preparation	**Excess gas disposal**
1. General well spacing rules[a]	18. Venting regulations
2. Building setback requirements	19. Flaring Regulations
3. Water setback requirements	**Production**
4. Predrilling water well testing requirements	20. Severance taxes[a]
Drilling the well	**Plugging and abandonment**
5. Casing/cementing depth regulations	21. Well idle time limits
6. Cement type regulations	22. Temporary abandonment limits
7. Surface casing cement circulation rules	**Other**
8. Intermediate casing cement circulation rules	23. Accident reporting requirements
9. Production casing cement circulation rules	24. State and local bans and moratoria[a]
Hydraulic fracturing	25. Number of regulatory agencies[a]
10. Water withdrawal limits	
11. Fracturing fluid disclosure requirements	
Wastewater storage and disposal	
12. Fluid storage options	
13. Freeboard requirements	
14. Pit liner requirements	
15. Underground injection regulations	
16. Fluid disposal options[a]	
17. Wastewater transportation tracking rules	

[a]State regulation of this element is described, but the element either does not lend itself to interstate comparisons, or is not tracked in sufficient detail to do so, and is therefore excluded from statistical analysis.

For the most part, the state regulatory elements examined in this report are not subject to overlapping federal regulation. This is partly by design—for example, we did not include state "green completion" requirements in large part because US Environmental Protection Agency (EPA) performance standards now require them nationally.[11]

[11] See EPA, *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews*, 77 Fed. Reg. 49490, 49492 (2012) ("For fractured and refractured gas wells, the rule generally requires owners/operators to use reduced emissions completions, also known as ''RECs'' or ''green completions,'' to reduce VOC emissions from well completions").

3.2 Methodology

Regulatory data were collected for each state by direct examination and interpretation of state legal documents: state codes, legislation, agency regulations, and so on. Because most states regulate parts of the development process through case-by-case permitting, we also included permit guidance, permit applications, and other relevant documents in our survey. Note, however, that the case-by-case character of regulation by permitting makes it very difficult to evaluate regulatory stringency and some other characteristics—we were only able to say whether a state regulates a given area via permit. Regulatory data are current—to the best of our ability—as of March 1, 2013. Changes to state rules since that date are not included in this review.

Our review includes only enacted and in-force regulations, with two exceptions. First, regulations for one element—fracturing fluid disclosure—have undergone rapid change in recent years, and we therefore felt it appropriate to note states that have proposed but not yet enacted rules in this area (see Section 5.3.2). Second, we treated New York's 2011 set of proposed regulations[12] as if it has already been enacted—primarily because the New York proposal is relatively comprehensive, and can therefore be treated as representative of the state's planned regulatory approach.

To vet the information found, oil and gas regulators were contacted in each state and asked to review the information for accuracy and completeness. Most states responded in some way. For those that did not, and for general review purposes, our data were reviewed by industry representatives, academic colleagues, and others with relevant experience. Earlier versions of maps based on our research were also made available for public comment on the Resources for the Future website. This report incorporates revisions based on the input and comment of all these groups. Nevertheless, we made all final judgments regarding the interpretation of rules and statutes, and any errors are ours alone.

We have made every effort to find any and all state regulations relevant to each element in our study, but errors of either interpretation or omission are possible. In particular, in many cases we were unable to find evidence of regulation for some states and elements. Acknowledging the small but real chance that regulations do exist but that we failed to find them, we describe such cases as "no evidence of regulation found" rather than "no regulation."

4. General Findings

4.1 What We Know and What We Don't

Our analysis reveals important information about state shale gas regulation. We show how widely regulated a given element is across states and how states regulate that element. We also show what regulatory tools—command and control, performance standards, case-by-case permitting, and others, such as liability rules—states are using for each regulatory element and across all of them. And in *some* cases, we can determine how stringently states regulate. For many elements, such as setback restrictions and casing/cementing depth requirements, command-and-control regulations are quantitative and clearly stated. This enables basic comparisons among states—how many elements

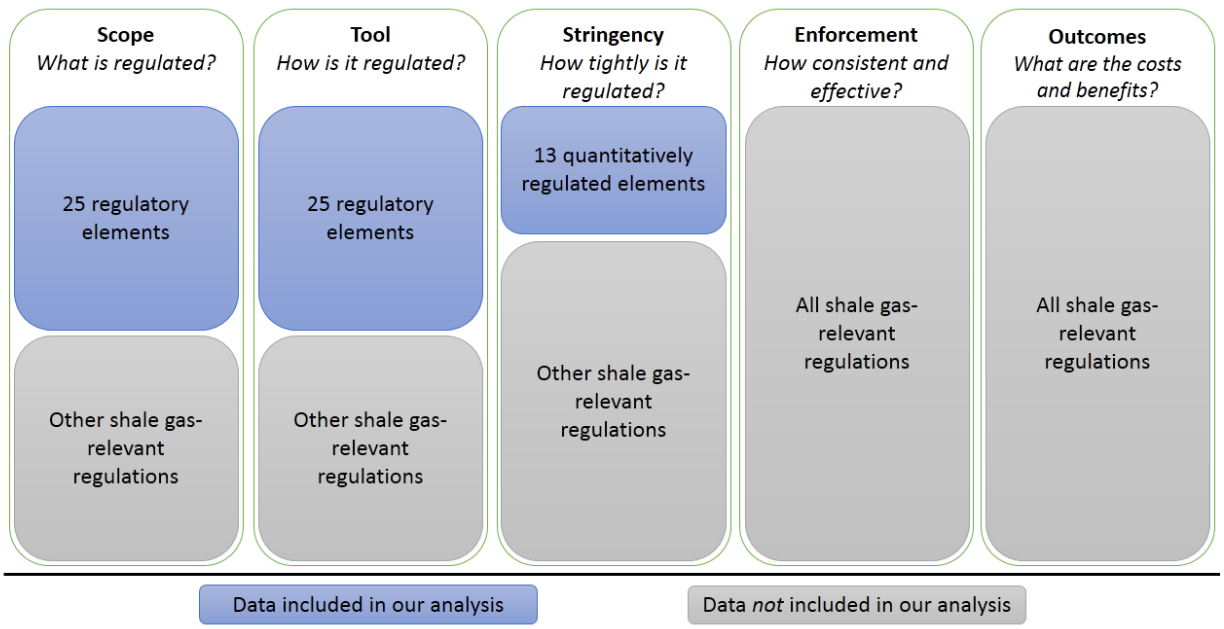
[12] See "High Volume Hydraulic Fracturing Proposed Regulations," New York State Department of Environmental Conservation, accessed May 7, 2013, http://www.dec.ny.gov/regulations/77353.html, proposing modifications to 6 NYCRR Parts 52, 190, 550–556, 560, and 750.

are regulated, which tools are used, and, for a subset of elements, how stringently each state is regulating.

But it is equally important to be clear about what we cannot say. First, for many elements and states, it is not possible to draw conclusions about regulatory stringency. Some elements, like fracturing fluid disclosure requirements or cement type regulations, are not easily quantifiable or comparable. Moreover, states may not use command-and-control regulations even for those elements that are quantifiable in principle. If a state uses case-by-case permitting, it would be necessary to collect data on permit conditions to draw any conclusions about regulatory requirements. This was beyond the scope of our work.

More deeply, *this or any analysis of regulations alone is inadequate to draw conclusions about the quality, environmental adequacy, or economic justifiability of state regulatory approaches.* More information would be needed to make such evaluations (see Figure 3).

Figure 3. Information Needed To Fully Evaluate and Compare State Shale Gas Regulations



One important type of information not included in this analysis is enforcement: states commit differing levels of resources to inspections and enforcement of regulations, possibly with varying degrees of success. How regulators and inspectors interpret and enforce regulations is as important as their stated form and stringency. States with what appear to be low-stringency regulations on the books may actually enforce them strictly and comprehensively, giving them more stringent regulation in practice than states with ostensibly strict rules but ineffective or inconsistent enforcement.

Full evaluation of state regulations also requires information on outcomes. Specifically, how successful are regulations at reducing environmental and other risks associated with shale gas development, and what are the costs of those regulations? Regulating an element or regulating it more stringently may or may not appreciably reduce risks, and doing so may or may not be justified given the cost of compliance.

Judging the absolute or relative quality and/or effectiveness of state regulations requires both types of information—enforcement and outcomes/costs—in addition to the understanding of the underlying regulations themselves presented here. Moreover, our analysis, as noted, considers only a subset of state regulations relevant to shale gas. We therefore refrain from making broad judgments about the quality of any state's regulations, and none should be implied. More precisely, our analysis reveals large differences among states' shale gas regulations, as discussed in the following section. But this does not necessarily imply wide differences in outcomes or regulatory quality. Differing local conditions may mean that different regulatory approaches yield similar outcomes, or it might even be true that environmental outcomes are not greatly influenced by regulatory differences.

4.2 High-Level Comparisons

The first and simplest way to look at our regulatory data is to make high-level observations across regulatory elements. These observations reflect the basic questions that policymakers consider: what activities/elements to regulate, what regulatory tool to use, and how stringently to regulate.

In the following subsections, findings for each of these three basic questions are discussed. In each case, the discussion excludes a small portion of the data for purposes of clarity:

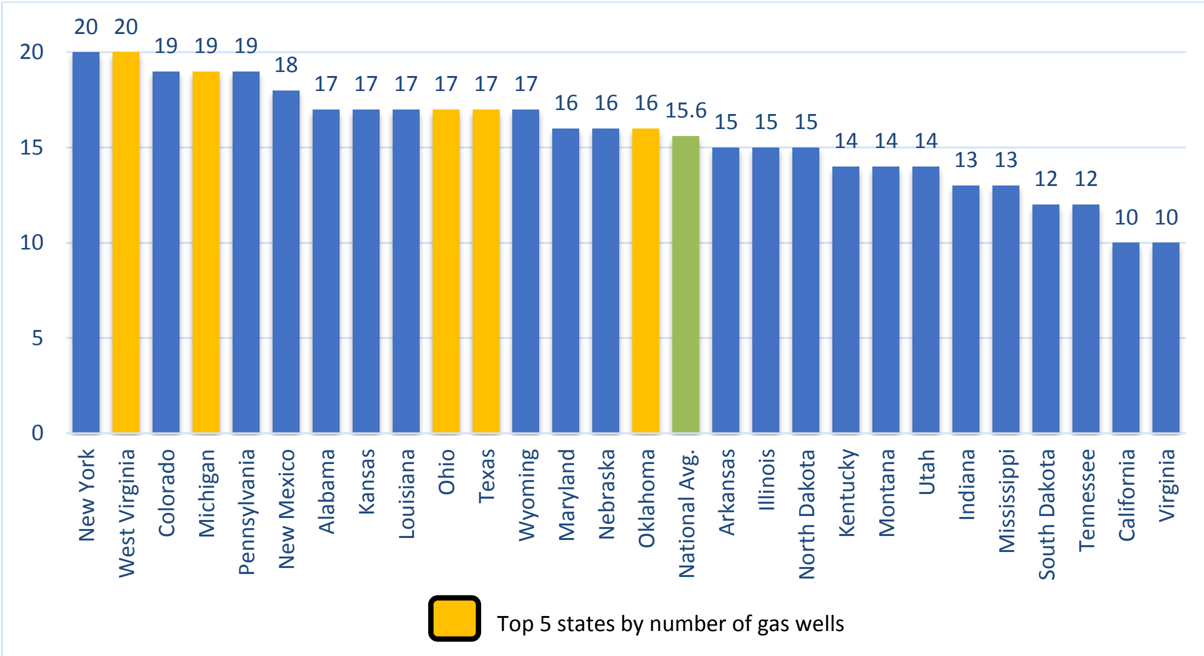
- Of the 25 elements, 5—well spacing rules, fluid disposal options, state/local moratoria, number of regulatory agencies, and severance taxes—are not readily comparable among states, were not investigated in sufficient detail to do so, or are not regulations in the same sense as the other elements. These were excluded, leaving 20 elements for purposes of state comparisons.
- As noted, four states—Georgia, North Carolina, New Jersey, and Vermont—have little or no shale gas development and no gas wells at all as recently as 2011. These states have had relatively little reason or opportunity to regulate development and were therefore excluded from the following comparisons, leaving 27 states in our analysis.

4.2.1 How Many Elements Does Each State Regulate?

For each of these 20 elements, we first recorded whether we found any relevant regulation in each of the 27 states with significant development, regardless of its form or stringency. Even at this general level, we found great heterogeneity among states. Only New York (including its 2011 proposed rules) and West Virginia regulate all 20 elements. Three states (Colorado, Michigan, and Pennsylvania) regulate 19. All of the top five states by number of gas wells (based on 2011 EIA data) regulate at least 17 elements. The average number of elements regulated is 15.6. All states (again, excluding the four states without significant development) regulate at least 10 of the elements in our analysis, with Virginia and California regulating the fewest. Between these extremes, we found relatively smooth variation among states (see Figure 4).

This variation illustrates differences among state regulatory approaches and is a factually accurate representation of how broadly each state regulates across the elements in our analysis. *But it is at best an extremely rough measure of the overall extent of any state's shale gas regulation.* One certainly should not assume that states that regulate more elements regulate development more tightly, much less more effectively. As noted, our analysis includes only a narrow subset of regulations relevant to shale gas, and although we believe it is a representative sample, it is only a sample.

Figure 4. Elements Regulated by State



4.2.2 What Regulatory Tools Do States Use?

Simply counting elements regulated reveals only superficial differences and permits only the most basic comparisons among states, however. Deeper analysis reveals differences among states' choice of regulatory tools.

Economists recognize two broad types of regulatory tools with which to internalize externalities: command and control and performance-based approaches, including those using economic incentives (though distinctions between the two are not always clear). At the command-and-control end of the continuum are highly prescriptive regulations mandating that the regulated entity do a specific thing, without regard to special circumstances, economic conditions, and the like. For example, a setback rule could prohibit drilling within 500 feet of a stream, or a technology mandate might require use of a specific cement type to isolate groundwater from the well.

Further toward the incentive end are performance standards, which give firms flexibility to choose actions sufficient to meet the standards.[13] Rather than requiring a specific number of feet of setback or a specific casing technology, for example, a performance standard might require that concentrations of specified pollutants in streams near drilling sites not exceed a certain level, or that a pressure test on the cement casing not exceed a given reading. Compliance costs are generally lower for performance standards relative to command-and-control rules.

For a performance standard to be meaningful, however, it is necessary to base it on something measureable. If a standard is too vague, it is not enforceable. For example, requiring firms to limit

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[13] At the extreme end of the spectrum are policies that create a price on the externality, like a Pigouvian tax or a cap-and-trade program.

venting or flaring to circumstances where it is "economically necessary" or to avoid such practices when they "create a risk to public health" does not create an enforceable rule.[14] We refer to such "rules" as "aspirational" or "discretionary" standards (and group them with other types of regulation into the "other" category in Figure 5).

A third regulatory tool is case-by-case permitting. Instead of being required to meet command-and-control requirements or satisfy performance standards, operators are required to specifically satisfy regulators for each activity. Usually, this involves a formal permit application, followed by regulator review. Regulations vary in the degree of discretion left to regulators in reviewing permits, but the key distinction is that *some* discretion remains in regulators' hands (otherwise the regulation would be a command-and-control rule or performance standard, with permit reviewers merely checking for compliance).

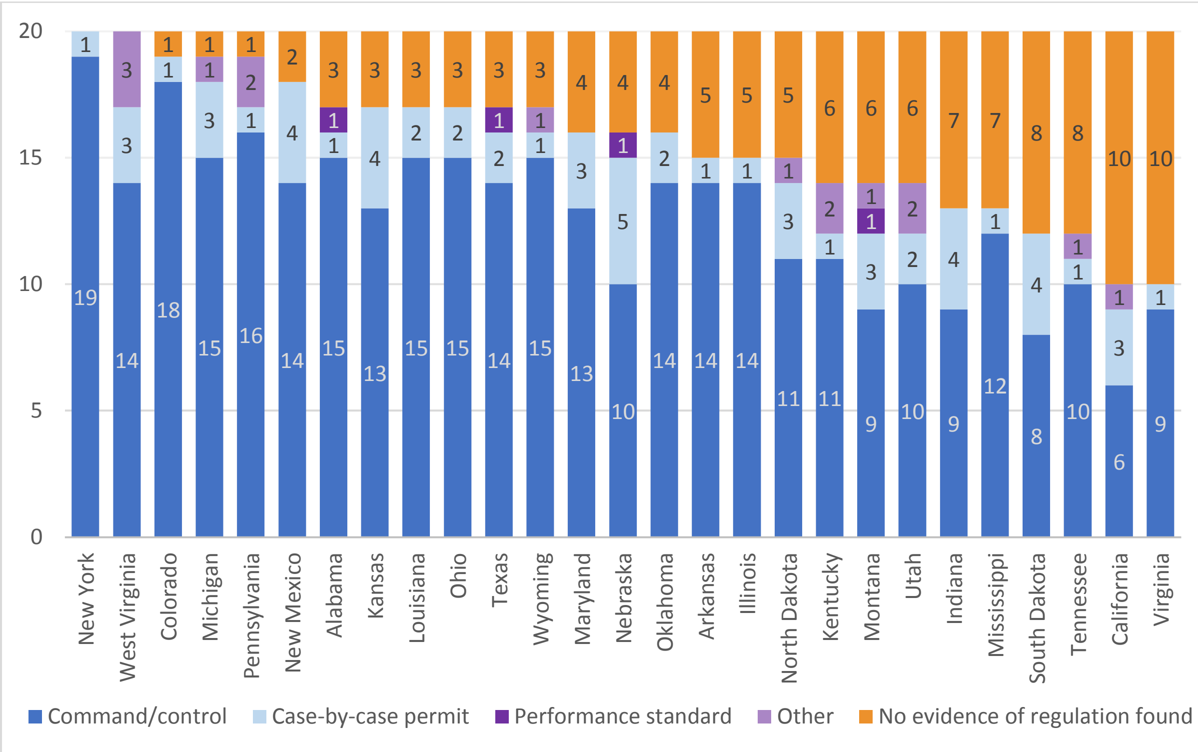
Case-by-case permitting has some advantages: it delegates decisionmaking to expert regulators and may prevent firms from evading regulation through technical compliance (complying with the letter but not the spirit of regulations). But it has drawbacks: it is administratively costly because each permit must be reviewed, and it may not be uniformly enforced (though this is possible with any regulatory tool). And it lacks transparency—it is difficult or impossible to know in advance what is necessary for permit approval, or for outside observers to gauge regulatory requirements and stringency.

In our analysis, we note the predominant regulatory tool used by each state for each regulatory element (see Figure 5.) Substantial overlap exists—states may use a hybrid approach, with more than one regulatory tool for an element. For example, states frequently use a command-and-control regulation to set a statewide minimum standard but still require case-by-case permit review or allow exceptions or variances from the statewide standard upon application and approval. In such hybrid cases, we considered command and control to be the primary form of regulation. Only elements for which states use case-by-case permitting exclusively are so categorized.

Among the states and regulatory elements in our analysis, command and control is the predominant tool, accounting for 81 percent of observed regulations (and 64 percent of all observations, including those for which we found no regulation). This is perhaps not surprising given our treatment of command and control as the predominant tool when it is part of a hybrid regulatory approach. Primary regulation via case-by-case permitting is also somewhat widely used, at 14 percent of regulations overall, and up to 20–25 percent (4 or 5 of 20 elements) in some states. Performance standards and other types of regulation, including those we call discretionary standards, are less common. No state uses a performance standard for more than one element.

[14] However, such standards might be enforceable and meaningful to the extent that they are incorporated into a permit process—if the state allows venting or flaring only with a permit, inspectors could use these standards to guide their judgment. An alternative, enforceable standard for venting and flaring might limit firms' per-well carbon dioxide-equivalent emissions.

Figure 5. Regulatory Tools Used



Based on this analysis alone, it is possible to show only the variation in approaches. We cannot draw conclusions about which regulatory tools are best, either on environmental or cost-effectiveness grounds, much less which states have chosen a better mix of tools.

However, economists have considered the relative merits of each tool, using various criteria for comparing instruments, all of which should be considered when a regulatory strategy is to be devised or analyzed. These criteria include regulatory capacity, the ability to raise revenue, treatment of uncertainty, flexibility to changing conditions, transparency, equity and distributional effects, and political considerations.

Based on theory and many studies, economists generally prefer performance standards to command-and-control approaches because they afford regulators greater flexibility in meeting regulatory goals and allow for more variation in compliance options. Because the cost of different compliance options varies, and because lawmakers and regulators often lack good information about this variation, the flexibility afforded by performance standards can have a significant impact on the cost of regulatory compliance.

However, the more flexibility granted by regulations, the greater the administrative burden of evaluating firms' compliance. If regulatory resources are constrained, command and control may be the preferred approach—or states (legislators and/or regulators) may prefer the relative simplicity of command-and-control approaches. Case-by-case permitting can give operators the greatest flexibility but, as noted, may also require the greatest regulatory resources.

4.2.3 How Stringently Does Each State Regulate?

For many elements in our analysis, our data allow us only to say whether a state regulates and, if so, what regulatory tool it uses. It is often impossible to determine how stringent state regulations are. For example, regulation via case-by-case permitting is generally not transparent—it is difficult or impossible to determine what regulators require, or even whether requirements are consistent. In other cases, regulations are qualitative and difficult to evaluate or compare—many states, for example, limit venting of excess gas to narrow circumstances or phases of development but do not impose quantitative limits.

However, for some elements, many states use quantitative regulations—for example, setback rules require wells to be sited a certain number of feet from buildings, or regulations require wells to be cased and cemented to a certain number of feet below the water table. In these cases, it *is* possible to measure stringency and make comparisons across states. The 13 elements shown in Table 2 are regulated quantitatively by at least some states.

Table 2. Elements Regulated Quantitatively in at Least Some States

Site selection and preparation	**Wastewater storage and disposal**
1. Building setback requirements	8. Freeboard requirements
2. Water setback requirements	9. Pit liner requirements
3. Predrilling water well testing requirements	10. Wastewater transportation tracking rules
Drilling the well	**Plugging and abandonment**
4. Casing/cementing depth regulations	11. Well idle time limits
5. Intermediate casing cement circulation rules	12. Temporary abandonment limits
6. Production casing cement circulation rules	**Other**
Hydraulic fracturing	13. Accident reporting requirements
7. Water withdrawal limits	

Furthermore, it is possible to measure stringency across these regulations for each state by normalizing the stringency of each regulation to the same scale. This is done by defining a regulatory range between the most and least stringent state rule for each element, placing each state on that range, then normalizing the range to a 0–1 (or 0–100 percent) scale.[15] This allows stringency to be compared not only between states, but also across otherwise dissimilar regulatory elements.

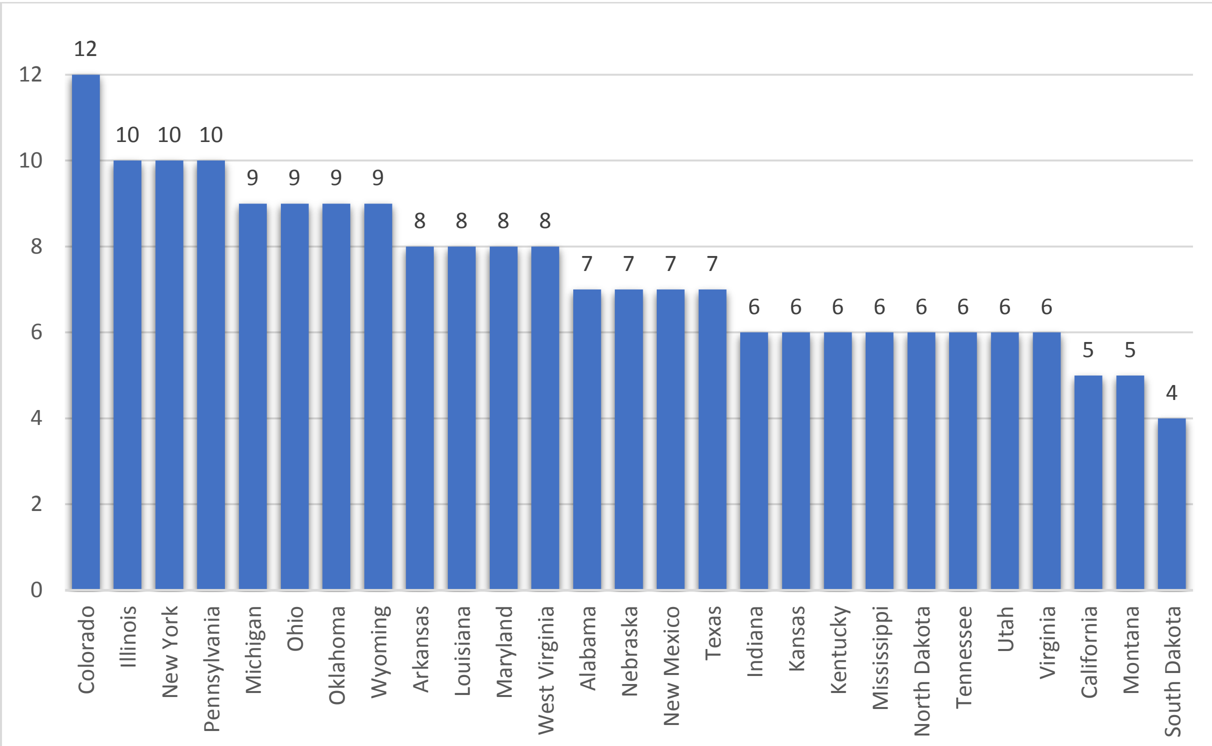
No state quantitatively regulates more than 12 elements, and some states regulate as few as 4 or 5 in this way (see Figure 6). Note that this measure says nothing about states' relative regulatory stringency—it is simply a count of how many elements are regulated quantitatively.

It is possible to use these data to find an average regulatory stringency for each state across quantitatively regulated elements. This measure does show the relative stringency of states' quantitative regulations in our analysis.

[15] For example, if the most stringent state (say, West Virginia) requires wells to be set back 625 feet from buildings, and the least stringent state (say, New York) requires a 100-foot setback, then New York would be treated as "0" stringency and West Virginia as "1." If a third state (say, Pennsylvania) has a 500-foot setback rule, its stringency would be treated as 0.76.

But significant caution is warranted. The limitations of our data discussed above—the lack of information on enforcement, outcomes, and costs, and the limited scope of our chosen regulatory elements—still apply. Moreover, this analysis is restricted to quantitative regulations—regulations that use case-by-case permitting, for example, are excluded. This further limits its scope.

Figure 6. Number of Elements Regulated Quantitatively



Also, states often use command and control as their primary regulatory tool, setting a uniform statewide minimum standard, but allow operators to apply for exceptions. This is effectively a hybrid command-and-control/case-by-case permitting approach. In these cases, the stringency of the underlying command-and-control rule does not fully convey the stringency of the state's regulatory regime. Some states may allow only small variances in limited circumstances, whereas others may allow such significant variance that the underlying rule rarely applies. Our analysis cannot track these differences among states—it can only show each state's uniform, baseline requirements.

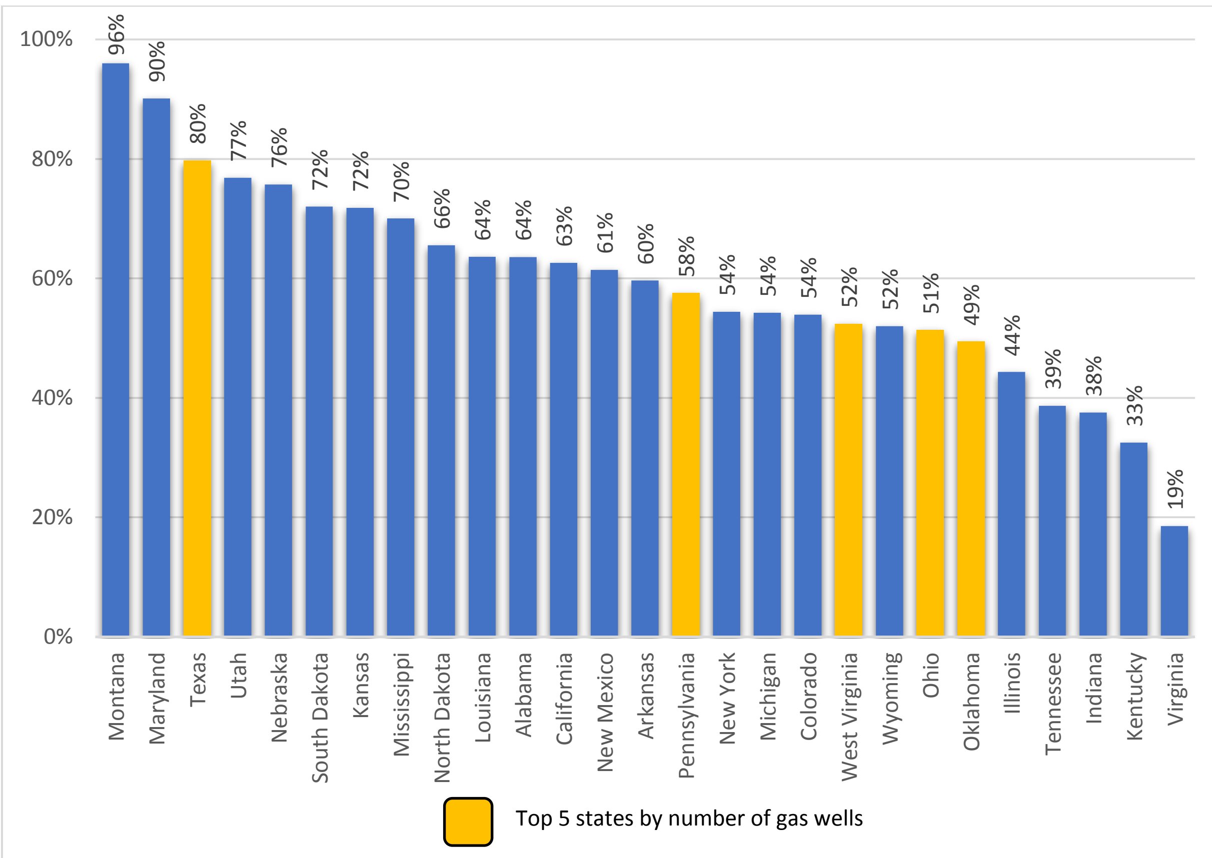
This stringency analysis—like our entire study—also makes no effort to measure the relative importance of different regulatory elements. It is possible, for example, that regulations on pit liner thickness have a much greater impact on environmental outcomes and/or compliance costs than regulations on how quickly operators must report accidents. Whether true or not, this would not be considered in our stringency measures. This analysis treats all regulatory elements as equally significant.

Moreover, differing conditions among states may justify regulating more or less stringently (or indeed, not regulating an element at all, as noted above). We explore the potential relationship between some such possible justifications and the heterogeneity we observed in Section 6 below, but the following analysis does not—and cannot—consider whether different levels of average stringency are justified or appropriate. Instead, it is simply an effort to identify those differences.

These limitations mean that the following tables and analyses should not be used to evaluate the *general* stringency or propriety of each state's shale gas regulations. It only shows states' relative stringency across the elements in our survey that they have regulated quantitatively. We don't know whether the stringency of these regulations corresponds to the stringency of other regulations—either those that cannot be quantified or those that can but are not in our data.

Given these caveats, the simplest approach to analyzing this stringency data is to rank states by the normalized stringency of their regulations for elements they regulate in a quantifiable way (see Figure 7). Recall that stringency is normalized to a 0–100 percent scale—a state at 100 percent stringency by this measure would have the most stringent regulations across all elements that it quantitatively regulates. Recall also that any element not regulated quantitatively by a state is excluded from that state's average stringency.[16]

Figure 7. Average Stringency of Quantitatively Regulated Elements



Ranking by stringency reveals significant differences among states. Montana regulates most stringently across these elements, with an average stringency of 96 percent, and Virginia regulates them least stringently, with an average stringency of 19 percent. But Montana regulates only five elements quantitatively, and neither Montana nor Virginia is a major shale gas producer. Among the

[16] With one exception: one element in our analysis, temporary abandonment time, refers to a regulator-created status. States that allow this status are treated as more stringent the lower the maximum time they allow wells to be temporarily abandoned. In this case, the stringency of states that do not allow the status at all can be measured—they all effectively allow no time in this status and are therefore treated as the most stringent states.

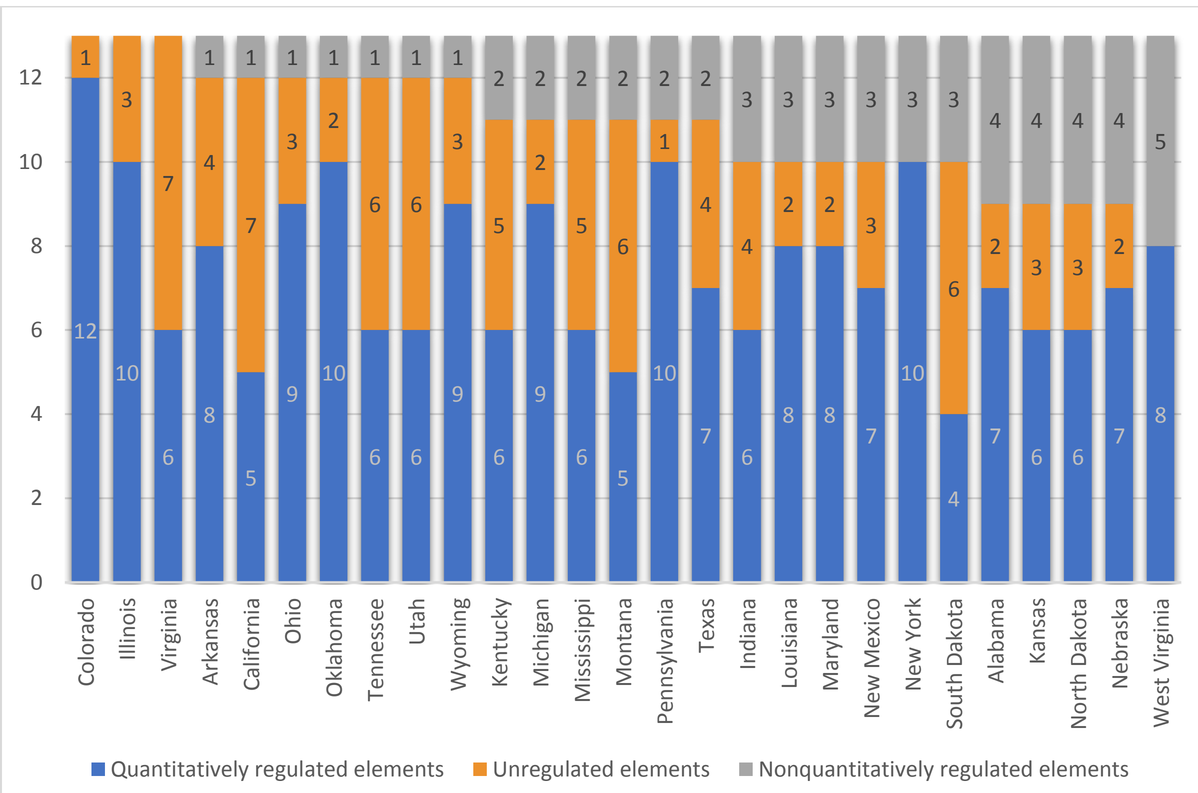
top five states (by gas wells in 2011), Texas is the most stringent across these elements (with an average 80 percent stringency), with the remaining four clustered between 49 and 58 percent stringency (recall that the four states in our study without *any* gas wells in 2011 were excluded from this and other statistical analyses).

When stringency is evaluated based on so few regulatory observations for each state, it is possible for one especially stringent (or not-so-stringent) regulation to distort a state's average stringency.

The above data consider stringency only for those elements that each state has regulated quantitatively. As noted, our data provide no way to measure stringency in cases where a state regulates with case-by-case permitting or uses some other unquantifiable approach. But some states appear to have no regulation at all for some quantifiable elements. For example, California appears not to regulate thickness of pit liners. It is arguably accurate to treat these cases as minimally stringent, rather than ignoring them as in the above analysis.

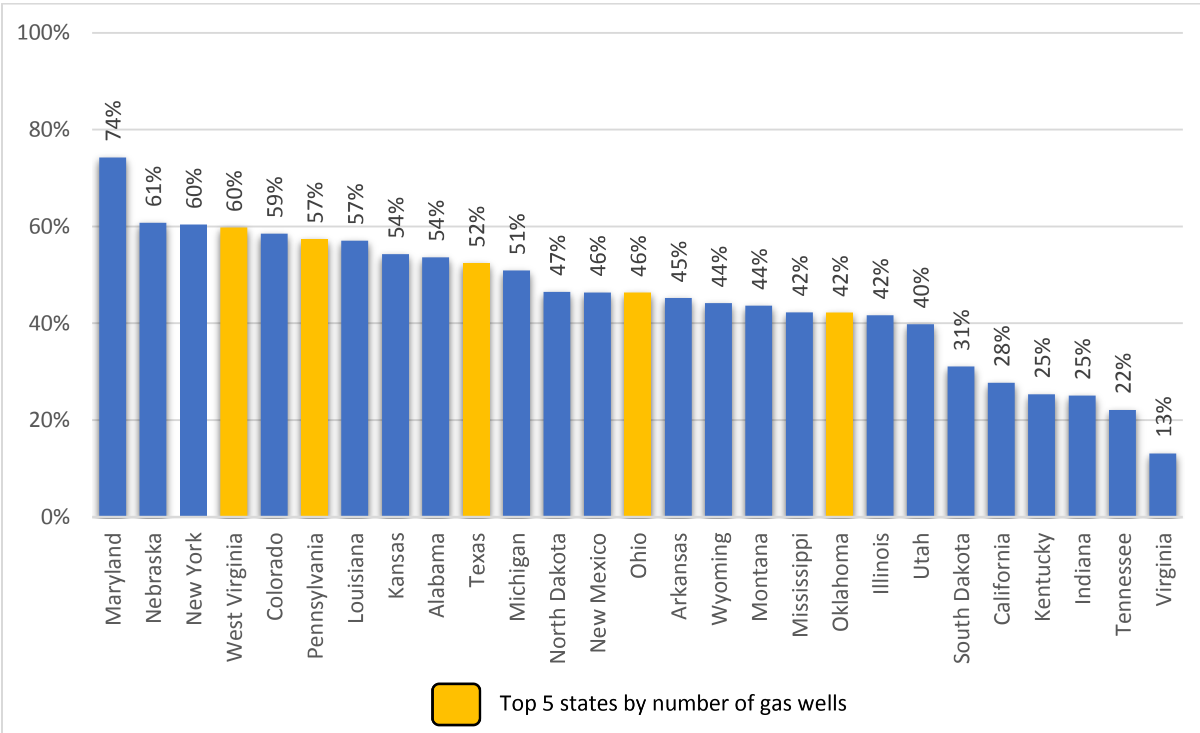
Figure 8 lists the count of quantitative regulations and instances where we found no evidence of regulation across the 13 elements in our analysis quantitatively regulated by states. The total of the two—the blue and orange bars in the figure—indicates the number of elements for each state for which we have information on the stringency of regulation (or lack thereof).

Figure 8. Elements with Quantitative Regulations—or No Regulation



We then assigned each state a zero stringency value for each element where we were unable to find evidence of any regulation, renormalized the stringency distribution for each element, and then reranked states by this "adjusted" stringency (see Figure 9).[17] To reiterate, this metric does not consider elements regulated in a non-quantitative way—states are not "penalized" for choosing non-quantifiable regulatory tools.

Figure 9. Average Stringency of Quantitatively Regulated and Unregulated Elements



In this adjusted measure of stringency across elements, the average stringency of all states is naturally lower because almost every state has at least one unregulated element for which it is assigned a 0 percent stringency. Maryland now appears most stringent at 74 percent, and Virginia remains least stringent at 13 percent. Among the top five states by number of wells (2011), Pennsylvania and West Virginia now appear more stringent than Texas across these elements.

Which of these two alternative measures of stringency is more appropriate is arguable. On the one hand, measuring stringency based only on quantitatively regulated elements (the first approach) is simpler and more precise. On the other hand, this approach leaves out important data: the fact that some states appear not to regulate some of these elements at all. This inflates the apparent regulatory stringency of states that regulate relatively few elements (but happen to do so relatively stringently). Treating apparently unregulated elements as minimally stringent (the second approach) corrects this.

To illustrate this, take two examples. Under the first approach, Montana is rated as the most stringent regulator, with 96 percent average stringency, and Colorado is in the middle of the pack, with 54 percent average stringency. But Montana's stringency average is based on only 5 elements, all of which are at over 85 percent normalized stringency. We found no evidence of regulation in Montana

[17] Note that this adjusted stringency measure is overly generous to states with no observed regulation in a given element, as it essentially credits them with the same regulation as the least stringent state (remember that this analysis defines the lower bound of the normalized stringency scale for each element). A more accurate representation might be to give states with no regulation negative stringency values, but accurately scaling these would be impossible.

for 6 other elements.[18] Meanwhile, Colorado quantitatively regulates 11 elements; for only 2 elements did we fail to find evidence of regulation in Colorado. It therefore may seem inaccurate to treat Montana as a more stringent regulator than Colorado across the group of 13 elements in our analysis. Although Montana does regulate more stringently than Colorado across the 5 elements it regulates quantitatively, for 6 other elements operator activity is apparently unrestricted in Montana. The second approach credits Colorado for regulating this activity: Montana's average stringency drops to 44 percent, and Colorado's increases slightly to 59 percent.

4.3 Heterogeneity

Across all these measures—number of elements regulated, choice of regulatory tool, and stringency of quantitative regulations—states vary, particularly in numbers and stringency of regulations. Heterogeneity is further explored element-by-element in the next section.

To some extent, this heterogeneity is not surprising. States' regulation differs greatly in many areas.[19] Even for something as simple as state income taxes, not only do rates differ greatly among states (though not by as much as severance tax rates—see Section 5.6.1 below), but a substantial minority of states do not have an income tax at all. For more complex regulatory schemes, whether insurance, banking, or oil and gas development, some heterogeneity should be expected.

Moreover, the observed regulatory heterogeneity among states has many possible explanations. Some sources of heterogeneity are appropriate in that they can be justified on economic efficiency, risk minimization, or even equity grounds. Examples include differences in physical or geographic conditions, such as the type and depth of groundwater resources or the amount of surface water. These may influence the significance of different risks and, therefore, whether and how they are targeted by regulation. Population density and distribution may have similar effects.

Other sources of heterogeneity are less readily justified on the above grounds—whether they lead to better outcomes across states is debatable at best. Some of these are political in nature, although one could argue that differing attitudes about the trade-offs between risk and economic development that may be captured by political differences are a good reason for different regulatory approaches.

Further factors, like the historical or current level of oil and gas development, could also be sources of heterogeneity. But if so, these are probably evidence of underlying factors, such as the relative experience regulators have (or, possibly, the degree to which they have been captured by industry), that may have little to do with efficiency, minimizing risk, or equity. In other words, states with more experience with development might write better, more cost-effective regulations, or the opposite could be true—a larger industry presence could create a greater risk of regulatory capture. But experience (or, obviously, capture) alone does not justify heterogeneity. In fact, if states' lack of experience (or the inertia of outdated rules) leads them to regulate suboptimally, differences in experience might explain the observed heterogeneity but would not justify it. Geological and hydrological differences may, on the other hand, both explain *and* justify observed heterogeneity.

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[18] Montana does regulate the remaining 2 elements in this analysis, but not quantifiably—these are ignored under both approaches.

[19] See, e.g., Slemrod, J., The Etiology of Tax Complexity: Evidence from U.S. State Income Tax Systems. 33.3 Public Finance Review 279 (2005): 279-99.

Regardless of whether it is surprising, and regardless of its underlying causes, regulatory heterogeneity (and dynamism) have important implications for shale gas development and for managing related environmental risks. Firms and other stakeholders must confront a different regulatory environment in each state, with different trade-offs between stringency of regulation, environmental outcomes, administrative cost, distributional impact, and other factors. Especially considering the lack of transparency in many states' regulations, this heterogeneity makes tracking, much less evaluating, shale gas regulation difficult.

This is not to suggest, however, that heterogeneity is evidence itself that states are not doing a good job. Though heterogeneity does have costs, it does not imply that any state is necessarily under-, over-, or improperly regulating risks related to shale gas development. As noted, there may be good reasons for the heterogeneity we observed. But neither should the heterogeneous status quo simply be accepted. Some have argued for a greater federal role in shale gas regulation, or at least minimum federal standards. We take no position in that debate here. But heterogeneity calls for explanation.

We address heterogeneity in two ways. First, as we discuss state regulations in detail in the next section, we take a qualitative look at heterogeneity among them, discussing geographical patterns and related observations as we describe each regulatory element. Second, in Section 6 we take a quantitative look, comparing regulatory heterogeneity to real-world conditions that vary across states in an effort to identify potential sources of the heterogeneity. This is only a preliminary move toward identifying the actual causes of heterogeneity, however.

5. State Shale Gas Regulations

This section describes the state shale gas regulations in our study in detail. For clarity, the discussion is organized by regulated element (rather than by state) and generally follows the shale gas development process. The descriptions of each element are illustrated with a map showing states' different regulatory approaches. The same information is organized by state (rather than by regulatory element) in tables in Appendix 5.

Regulations covering development of new wells (by far the largest and most complex group) are discussed first, followed by regulations on production, and then well end-of-life. A final subsection describes other state interventions, like accident reporting and bans or moratoria. The majority of state shale gas regulation applies to the initial phases of the development process. This may indicate that state legislators and/or regulators believe that initial site selection and the drilling, cementing, fracking, and wastewater handling practices that are concentrated in the beginning of a well's life are the largest drivers of risk associated with shale gas development. In contrast, relatively few state regulations apply to producing wells. It is only when wells reach the end of their productive life that significant regulatory oversight returns, governing how and when wells can be idled or abandoned.

Describing this many data points requires simplification; therefore, judgment calls have to be made about how to describe or categorize regulations. This is particularly true with respect to our maps. The purpose of the text in this section is to expand on those maps, explaining nuanced differences between regulations and judgment calls we have made. Nevertheless, it is not possible to convey every detail.

Note that citations for each of the regulations discussed are included in the matrix in Appendix 5, categorized by state and regulatory element.

In addition to exploring the substance of regulation, the subsections on some elements provide limited examples of how regulatory content has recently changed. Although these are only limited examples from a broad collection of statutory and regulatory changes, they show the types of regulatory dynamism occurring in the face of expanding shale gas development.

Scholars only rarely have the opportunity to see a rapid economic change associated with a somewhat rapid variety of regulatory responses. Shale gas development in the United States has provided this unusual case study, which offers important lessons about the motivations, obstacles, laws, and politics that underlie legislative and administrative responses to change.

As gas development has boomed due to an expansion of horizontal drilling and hydraulic fracturing, municipalities, states, and regional entities have responded in very different ways. So far, state modifications of legislation and regulation have come in several forms.

- Some states, like Colorado,[20] Ohio,[21] Pennsylvania,[22] and West Virginia,[23] have made relatively comprehensive revisions to their oil and gas codes.
- Others, like Arkansas,[24] Montana,[25] and Texas,[26] have made more targeted changes.
- In some cases, states have not only modified regulatory content, they have also expanded the number of oil and gas staff available to enforce regulations and provided new funding and training requirements for these staff.[27]

Finally, we make initial geographical observations of any heterogeneity for each element. This heterogeneity is explored more deeply and quantitatively in Section 6.

5.1 Site Selection and Preparation

Shale gas development is regulated from the very beginning of the process, before any construction or drilling begins. Regulations in many states restrict where wells can be sited or require groundwater to be tested before drilling can begin. The local nature of most (though not all) risks from shale gas development—and, of course, the immobility of wells and infrastructure once positioned—make site selection an important regulatory focus.

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[20] Colorado Department of Natural Resources, Oil and Gas Conservation Commission (COGCC), final rule amendments, December 17, 2008, accessed May 7, 2013, http://cogcc.state.co.us/RuleMaking/FinalRules/COGCCFinalRuleAmendments_121708.pdf.

[21] Ohio S.B. 315, enrolled, http://www.legislature.state.oh.us/BillText129/129_SB_315_EN_N.pdf.

[22] Pennsylvania Act 13 (H.B. 1950), enrolled, accessed May 7, 2013, http://www.ctbpls.com/www/PA/11R/PDF/PA11RHB01950CC1.pdf. Partially reversed by Robinson v. Commonwealth, 2012 WL 3030277 (2012); currently under cert. review by the Pennsylvania Supreme Court.

[23] West Virginia H.B. 401, enrolled, accessed May 7, 2013, http://www.legis.state.wv.us/Bill_Status/bills_text.cfm?billdoc=hb401%20enr.htm&yr=2011&sesstype=4X&billtype=B&houseorig=H&i=401.

[24] Arkansas Oil and Gas Commission. Rule B-19, "Requirements for Well Completion Using Fracture Stimulation," accessed May 7, 2013, http://www.shalegas.energy.gov/resources/060211_arkansas_rule.pdf.

[25] Mont. Admin. Code 36.22.608 et seq., effective August 27, 2011 (full changes available online in "unofficial" form, accessed May 7, 2013, http://bogc.dnrc.mt.gov/PDF/FinalFracRules.pdf).

[26] Adoption of 16 Tex. Admin. Code § 3.29, December 13, 2011, accessed May 7, 2013, http://www.rrc.state.tx.us/rules/signed-adopt-3-29-Dec13-2011.PDF; proposed amendments to 16 Tex. Admin. Code 3.13 et seq., August 21, 2012, accessed May 7, 2013, http://www.rrc.state.tx.us/rules/prop-amend-3-13-Aug21-2012.PDF.

[27] West Virginia H.B. 401, enrolled version (passed and in effect December 14, 2011), in W. Va. Code 22-6A-7, requiring a $10,000 permit fee for each horizontal well location and $5,000 for each additional horizontal well at the same location, and requiring inspectors to have minimum levels of experience and receive minimum training.

For this reason, most states have uniform well spacing requirements that limit the number of wells in an area, and most also have some form of setback rules limiting the proximity of wells to certain buildings or features.

5.1.1 Well Spacing Rules

Generally, state well spacing requirements are based on designated geographic drilling units within which new exploratory wells must be located. Once exploratory wells find producible quantities of oil or gas, the oil or gas pool is deemed a "field" and specific field rules are developed, including spacing requirements. Several states also have boards that can establish drilling units or authorize different well densities for each field.

The drilling unit size is usually 640 acres (often corresponding to a Public Land Survey System section)—though some states also issue rules for larger or smaller areas. Within these units, states may regulate not only well spacing but a minimum distance from unit boundaries. Eleven states (Arkansas, California, Kentucky, Maryland, New Jersey, Ohio, Oklahoma, South Dakota, Texas, Utah, and Wyoming) regulate well spacing statewide with a minimum distance between wells, ranging from 100 to 3,750 feet—though these rules provide for various exceptions and may be superseded by field-specific requirements.

5.1.2 Setback Requirements

Setback restrictions regulate the distance between wells and other entities—like schools, homes, streams and water wells—that are thought to merit special protection and care. Buildings and water sources are the most common subject of setback rules. Most of the surveyed states have some form of setback restriction, and API best practices encourage separating well activity from both buildings and water.

5.1.2.1 Regulation

Most of the surveyed states (20, or about 65 percent) have building setback restrictions, ranging from 100 feet to 1,000 feet from the wellbore, with an average of 308 feet (see Map 2).[28] Setback rules may vary based on local conditions. In Ohio and Colorado, for example, high density, or urbanized, areas tend to have larger setbacks. Many states also provide for reductions or exemptions from their setback restrictions, often contingent upon signatures from the affected landowners in the area in question. In such cases, setback restrictions function as default rules around which landowners can contract.

States measure setback in different ways—both in terms of the features from which it must be measured and the parts of the shale gas operation that are used as the basis for this measurement. Building setback rules may apply to all "occupied dwellings,"[29] or only to specific structures like schools, hospitals, and churches. Some setback rules are quite broad, such as the following examples.

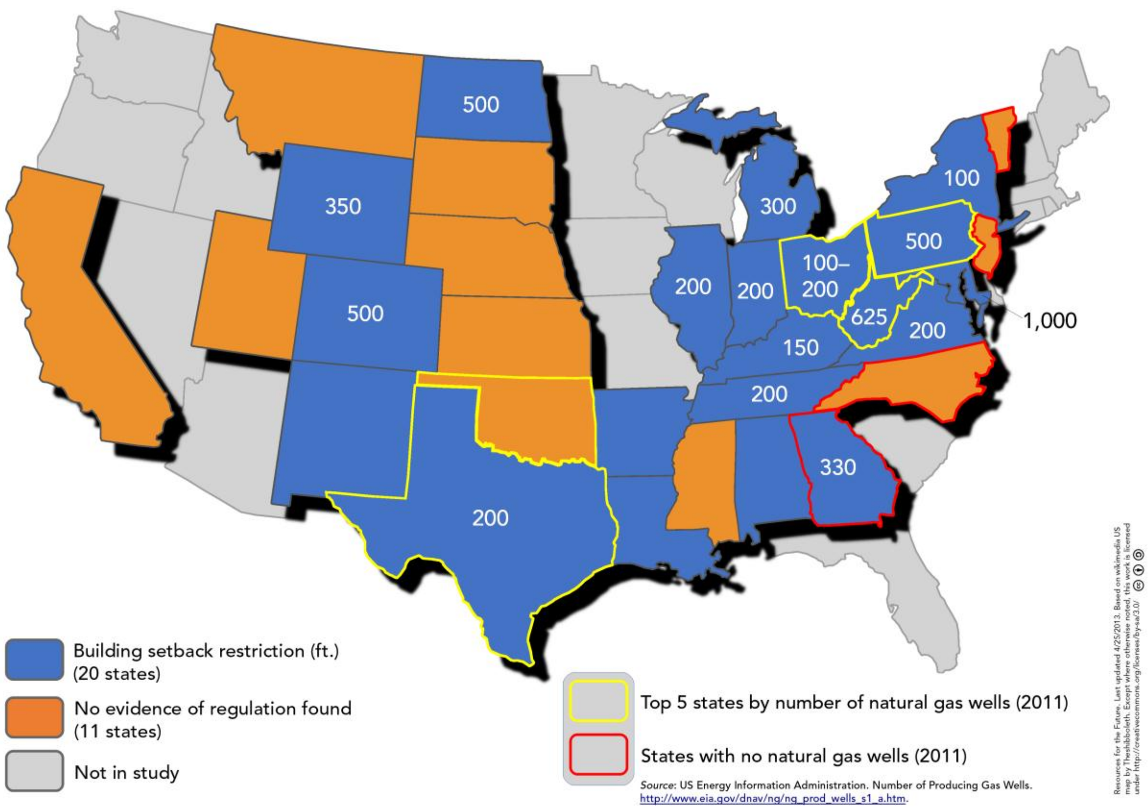
- Wyoming's setbacks apply to any structure "where people are known to congregate."[30]

[28] For states with setback requirements that vary depending on where wells are sited, this average is based on the minimum permitted setback in the state.
[29] See, e.g., 62 Ill. Admin. Code § 240.410(f), Md. Code Regs. 26.19.01.09; N.D. Admin. Code 42-03-02-28
[30] Operational Rules, Drilling Rules 3-22(b): 32

- Colorado ordinarily requires a 500-foot setback, but requires a hearing before a well can be drilled within 1,000 feet of a "high occupancy" building.[31]
- Louisiana has different setback rules for buildings owned by a person who is a party to a gas lease on the same property.

The usual practice is to measure building setbacks from the wellbore. Only states that measure in this way are shown with number values on the map below and are included in our statistical analysis of quantitative regulations. Setbacks measured from other points may have equal or greater real-world significance, however, and these measurements can be complex. Setback restrictions are sometimes stated in the alternative—for example, Pennsylvania mandates a 300-foot surface water setback from the vertical wellbore, or 100 feet from the edge of the well pad, whichever is greater.

Map 2. Setback Restrictions from Buildings



Other states do not regulate *building* setbacks, but may require setbacks from and/or to other features or human activities that, in practice, may have a similar effect, as shown in the following examples.

- California regulates the distance between wells and public streets, roads, or highways, but not buildings. Kansas does not have a setback restriction per se, except from a unit lease or boundary line, but the state does require additional safety measures (downhole shutoff valves) for wells near homes, churches, or schools.

[31] 2 Colo. Reg. 404-1-604(a)(3): 23

- Ohio has setbacks from mechanical separators, tank batteries, railroad tracks, and public roadways.
- Several states, including Colorado at 150 feet, also regulate distance from a surface property line.
- North Dakota requires flammable material to be kept at least 150 feet from the well.
- Other states have specific siting requirements for fluid storage pits, like New Mexico's 1,000-foot setback from buildings.
- New Mexico and Arkansas measure setback restrictions from pits and tanks, respectively, but not from wells.

API best practices state that "when feasible, the wellsite and access road should be located as far as practical from occupied structures and places of assembly."[32] The API standard may be useful as a guiding principle, but comparing it to state regulations is impossible because it is discretionary and dependent on local conditions. A well sited 100 feet away from a building in densely populated Ohio and one sited 500 feet away in much more sparsely settled North Dakota might both be "as far as practical." But if this is true, it is hard to explain how the rules in relatively densely populated Pennsylvania (500 feet) or Maryland (1,000 feet) meet the same standard.

Well setback from surface water features and/or water wells is also widely regulated, though not as widely as building setback. Of the states surveyed, 12 (39 percent) have setback restrictions from some body of water or water supply source; 9 of those have setback restrictions from municipal water supplies (measured from the well) ranging from 50 feet to 2,000 feet, with an average of 334 feet (see Map 3).[33] Though this average is slightly more than that for building setbacks, water setback rules may or may not be greater than those for buildings in the same state, as shown in the following examples.

- Ohio law requires only a 50-foot setback from water sources but 100–200 feet for building setbacks.
- New Mexico and Arkansas measure setback restrictions from pits and tanks, respectively, but not from wells.
- Michigan requires wellbores to be located at least 300 feet from "reasonably identifiable fresh water wells"[34]—an interesting example of a standard within a rule. Some other states have similar approaches.
- Colorado implements a complex scheme in which setback is required from designated water sources, with drilling-related activities more heavily restricted closer to the body of water.
- Michigan also has setback restrictions from municipal water sources—measured from well separators, storage tanks, and treatment equipment—that vary from 800 to 2,000 feet depending on the type of water supply.
- Kansas, New York, Pennsylvania, and Ohio have additional setback restrictions from other water sources, such as lakes, streams, and private water wells.

[32] API Guidance Document HF3, "Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing," First Edition, January 2011: Section 15.

[33] For states with setback requirements that vary depending on where wells are sited, this average is based on the minimum permitted setback in the state.

[34] Mich. Admin. Code r. 324.301(b)(5)

- West Virginia mandates a 300-foot setback from a naturally reproducing trout stream.
- North Dakota uses a discretionary requirement that wells may not be sited “hazardously near”[35] (or *in*) bodies of water. It is not clear whether or how this standard is applied during the permitting process.

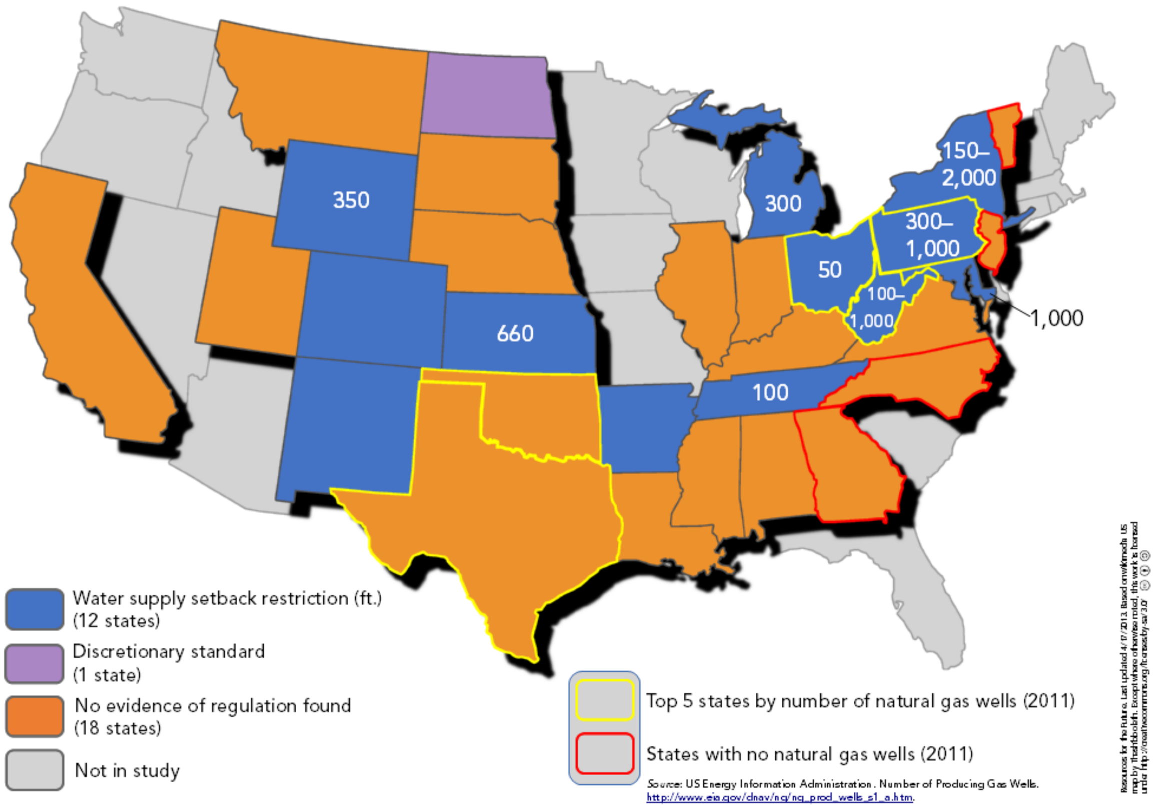
API best practice is, where feasible, to locate sites away from sensitive areas, such as surface waters and freshwater wells. API also recommends that “pits used for long term storage of fluids should be placed an appropriate distance from surface water to prevent unlikely overflows from reaching the surface water.”[36] As with building setbacks, this standard is impossible to compare directly to the fixed standards in most states. The API standard can be interpreted as more “stringent” than the majority of states surveyed that do not regulate water setback.

Setback restrictions (regarding buildings, water, or other features) generally do not appear to be addressed in permits. All states do require operators to state the exact location (latitude and longitude) of the well in permit applications, and most require detailed descriptions relevant to field or other boundary lines. This information is used to confirm compliance with well spacing regulations. In principle, it could also be used for setback regulation via permit—state regulators could refuse to approve permits for wells sited too close to certain features, even in the absence of a specific regulatory setback requirement (justified by general permitting authority), but we have found no evidence of this. It is possible that field-level permit requirements could impose setback restrictions, but, as noted above, due to the enormous volume of field rules for each state, such requirements were not examined in this study.

[35] N.D. Admin. Code 43-02-03-19

[36] API Guidance Document HF2, “Water Management Associated with Hydraulic Fracturing,” First Edition, June 2010: Section 6.3.2.

Map 3. Setback Restrictions from Water Sources



5.1.2.2 Dynamism

As drilling, fracking, or leasing in anticipation of these activities have grown, several states have updated setbacks and other site, well, or pit locational requirements.

In 2008, Colorado added a new provision that prohibits unlined pits in pathways where communication with surface or groundwater is likely to occur.[37] Colorado also implemented new statewide setback rules in 2013. Previously, the state required 350-foot setbacks of wells from buildings in high-density areas and 150-foot well–building separations elsewhere; the state has now implemented a uniform requirement that wells be set back 500 feet from buildings throughout the state. The Colorado Oil and Gas Conservation Commission also proposed best management practices to mitigate nuisances generated by well activity, among other changes to setbacks and conflicts between well activity and human populations.

Some states have also expanded certain minimum setback distances between wells and protected resources.

- In Pennsylvania, the vertical portion of unconventional (fractured) gas wells must now be 500 feet from water wells or buildings—a modification from a previous 200-foot requirement. [38]

[37] 2 Colo. Code Regs. § 404-1:902(g) (2013).
[38] 58 Pa. Stat. 3215(a) (changes, accessed May 7, 2013, http://www.legis.state.pa.us/WU01/LI/LI/US/HTM/2012/0/0013.HTM). Previous well location restrictions are located within 58 Pa. Stat. § 601.205.

The state also expanded the required distance between natural gas wells and public water supplies from 200 to 1,000 feet and between wells and streams or wetlands from 100 feet to 300 feet.[39]

- West Virginia similarly expanded the required distance between a natural gas well and a water well from 200 to 250 feet and added new setbacks, including 100 feet between well pads and streams (300 feet for naturally reproducing trout streams) and 1,000 feet between well pads and public water supplies.[40]

5.1.2.3 Heterogeneity

We found great heterogeneity among surveyed states' setback restrictions, both in terms of whether states have them and, if they do, how stringent they are. Generally, setback rules are more prevalent in the northeast and in mountain states: a contiguous block of 6 states from New York to Michigan and 3 mountain states (New Mexico, Colorado, and Wyoming) make up 9 of the 11 states with both building and water setback rules (Tennessee and Arkansas are the other two). Even in the contiguous Northeast block, however, setback rules vary greatly—from 50 to 2,000 feet for water, and from 100 to 1,000 feet for buildings.

5.1.3 Predrilling Water Testing

Predrilling water well testing establishes the baseline water quality for an area prior to drilling activity. If groundwater is later found to be contaminated, predrilling test results are important evidence for determining whether contamination is related to drilling activity.

5.1.3.1 Regulation

The majority of surveyed states (23) do not require baseline water well testing (see Map 4). In states that do require such testing, regulation usually requires testing of at least two wells within a specified radius from the proposed well location. This radius varies significantly among states, from 0.09 miles (Virginia) to 1 mile (North Dakota, Nebraska, and Oklahoma). The average radius is a bit less than ½ mile (0.44 miles). States may require predrilling testing only in certain areas— Colorado, for example, previously required testing in the Wattenberg field. It now requires groundwater sampling around most oil and gas wells. [41] Predrilling water quality tests usually apply to preexisting water wells, but some states require testing of groundwater generally or will specify an aquifer or other bodies of water that must be tested before drilling.[42]

API best practice is to test water samples from any source of water located near the well (determined based on anticipated fracture length) before drilling or before hydraulic fracturing. If this were a regulation, it would be, by definition, more stringent than at least the 23 states without a testing requirement. But it is impossible to directly compare the API standard to those states that do require testing because "near" is left to operator discretion under the API standard.

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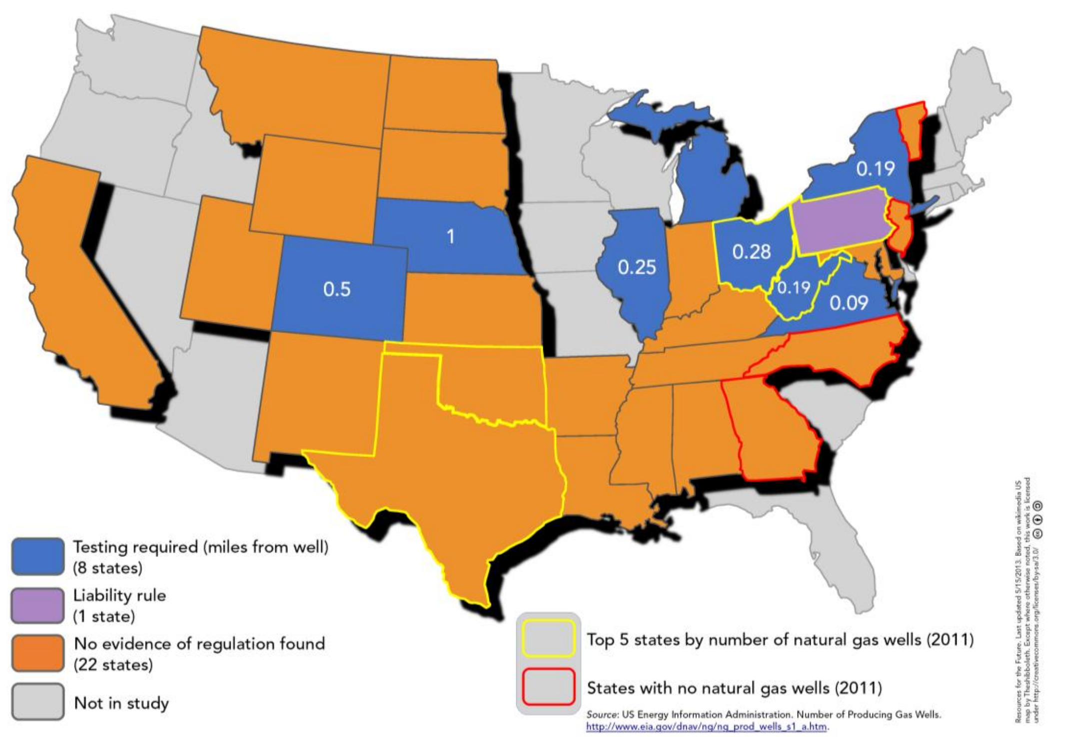
[39] *Id*.
[40] West Virginia H.B. 401, adding W.Va. Code 22-6A-12. W. Va. Stat. 22-6-21 previously required wells to be at least 200 feet from existing water wells.
[41] Colo. Oil & Gas Conservation Comm'n., Final Rule 609, http://cogcc.state.co.us/RR_HF2012/Groundwater/FinalRules/FinalRule609-01092013.pdf.
[42] See, e.g., 2 Colo. Code Regs. § 404-1:318A(e) (Westlaw 2012), requiring sampling in the Laramie/Fox Hills aquifer.

Pennsylvania has a unique approach. The state does not formally require predrilling testing. However, under state law, if tests are not done before development, operators are barred from claiming in future legal action that any alleged groundwater contamination was preexisting. In effect, this is a burden-shifting rule. Although plaintiffs retain the burden of proof that some contamination exists, such contamination within 2,500 feet of wells and within one year of drilling is presumed to be attributable to the operator defendant unless rebutted with predrilling testing evidence.

In the map below (and in the summary statistics in the previous section), Pennsylvania is not shown as requiring predrilling testing. This is narrowly true under the rule described—operators are not required to conduct testing—but in practice, the rule probably makes predrilling testing very attractive to operators in the state. In fact, such a liability rule might be more efficient than either alternative (uniformly requiring or not requiring testing). In Pennsylvania, operators can choose whether testing is necessary or cost-effective, and have a strong incentive to get that decision right. In practice, operators in Pennsylvania test most water wells that are covered by the rule—one study found that 90 percent of Pennsylvania water wells within 1,000 feet of gas wells in the Marcellus Basin were tested before drilling, dropping off to 41 percent at 3,000 feet.[43] This rule illustrates the wide variety of regulatory tools available to states and the difficulty of sorting them into simple categories.

Map 4. Pre-drilling Water Well Testing Requirements



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[43] Elizabeth W. Boyer, Bryan R. Swistock, James Clark, Mark Madden, and Dana E. Rizzo, *The Impact of Marcellus Gas Drilling on Rural Drinking Water Supplies* (Harrisburg, PA: The Center for Rural Pennsylvania, March 2012), 11, accessed May 7, 2013, http://www.rural.palegislature.us/documents/reports/Marcellus_and_drinking_water_2012.pdf.

5.1.3.2 Dynamism

Perhaps in response to a growth in development activity, several states have updated water testing and liability requirements.

- Pennsylvania expanded its rebuttable presumption that oil and gas operations caused contamination within 2,500 feet (rather than 1,000 feet) of the well and within one year (as opposed to six months).[44]
- West Virginia also modified its rebuttable presumption of contamination, providing that operations within 1,500 feet (as opposed to 1,000) feet "of the center of the well pad for a horizontal well"[45] presumably caused water contamination—an assumption that now can be countered with evidence that the pollution occurred more than six months "after completion of drilling or alteration activities,"[46] in addition to other defenses.[47]
- In 2012, the Ohio legislature updated its laws to require operators to test water wells within 300 feet of a proposed gas well in urbanized areas. In all other areas, sampling must occur within 1,500 feet of a proposed horizontal well.[48]
- In 2013, Colorado changed its rules to require that a maximum of four water wells be tested within a half-mile radius of oil and gas wells.[49]

5.1.3.3 Heterogeneity

Notably, the states in the East with predrilling water well testing requirements have much smaller radii for testing than do the western states. Predrilling testing requirements are more common east of the Mississippi: excluding the 4 states without significant production, 5 of 13 eastern states (6 if one counts Pennsylvania's liability rule) have testing requirements compared to only 3 of 12 western states. On the other hand, those western states that do require testing require it to be done over a much greater area: the smallest testing radius in the West (0.5 miles) is greater than the largest testing radius in the East (0.28 miles). Note also that the area covered by testing requirements increases non-linearly as the radius increases. For example, the 1-mile radius testing requirement in Nebraska and Oklahoma covers more than 16 times the area of Illinois' 0.25-mile radius requirement. Of course, wells may be much more common in the more densely settled (and wetter) eastern states, so it is unclear whether the western testing rules result in a greater number of actual tests.

5.2 Drilling the Well

Although drilling a shale gas well may take only a few weeks, compared to a production period measured in decades, much state regulation of development is focused on this brief phase. This appears to reflect a view that developers' drilling, casing, and cementing practices are critical to the long-term integrity and safety of wells, particularly in terms of groundwater safety. The following

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[44] For the old rebuttable presumption, see58 P.S. 601.208; for the new one for unconventional (fractured) wells, see58 Pa. C.S. § 3218.
[45] W. Va. Code 22-6A-18(b)
[46] W. Va. Code 22-6A-18(c)(4) (added by H.B. 401, December 14, 2011). For the previous requirement of 1,000 feet, see W. Va. Stat. 22-6-35.
[47] See W. Va. Stat. 22-6-35, (which lacks the six-month defense or other defenses provided by W. Va. Code 22-6A-18).
[48] Ohio S.B. 315, enrolled, accessed May 7, 2013, http://www.legislature.state.oh.us/BillText129/129_SB_315_EN_N.pdf.
[49] Colo. Oil & Gas Conservation Comm'n., Final Rule 609, http://cogcc.state.co.us/RR_HF2012/Groundwater/FinalRules/FinalRule609-01092013.pdf.

subsections summarize regulations applying to this development phase. Note that most of these regulations apply to all gas (or even all hydrocarbon) wells, not just horizontally drilled and hydraulically fractured shale gas wells. For those states with a history of conventional drilling, these regulations are often decades old and may not have been substantially updated to reflect new judgments or perceived risks from shale gas development. This is not necessarily problematic—the vertical component of shale gas wells is quite similar to a conventional well, and it is this part of the well that extends through groundwater-bearing strata. Regulation specific to the hydraulic fracturing process is discussed in the next section.

The primary methods of maintaining well integrity are adequate casing and cementing of the wellbore. Poor casing and cementing can provide a potential conduit for groundwater contamination. Both are heavily regulated by almost all states with shale gas development.

5.2.1 Casing and Cementing Depth

Casing is steel pipe of varying diameter that separates the wellbore from surrounding rock. Casing can be divided into four general types, in decreasing order of diameter. Conductor casing is set at the surface in many cases, including in conditions where surface soils may cave during drilling. Surface casing is then set, followed by intermediate and production casing, each set within the preceding, larger-diameter casing. This creates a series of concentric cylinders—the casing string. Cement is circulated within the gap (annulus) between each layer of casing.

5.2.1.1 Regulation

Almost all states in our analysis regulate the depth to which well casing must extend and be cemented (in almost all cases, these regulations refer specifically to surface casing). Of the surveyed states, 21 have specific casing and cementing requirements; 15 of these require casing to be set and cemented to a specified *minimum* depth below the base of layers or zones containing freshwater—between 30 and 120 feet, with an average of about 64 feet (see Map 5). Note that these values are minimums—local geology or other conditions may lead regulators to require casing to be set and cemented even deeper when granting permits.

Five states eschew statutory minimums in favor of performance standards or other well-specific regulations, such as a requirement that casing must be set and cemented to "in a manner sufficient to protect all fresh water."[50] A further three states do not make minimum depths or performance standards explicit in their statutes or regulations but do review cementing depth in their permit processes. In only two states—Vermont and Virginia—were we unable to find evidence of casing/cementing depth regulation (and, as noted above, Vermont has little if any oil and gas development).

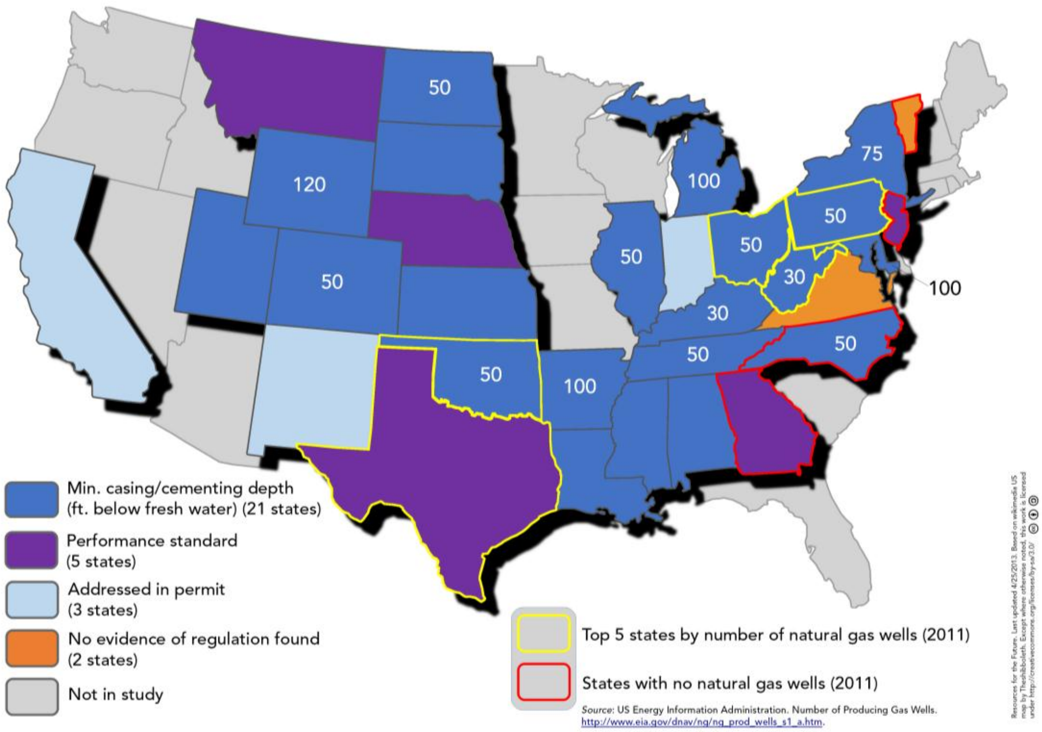
In Kansas, casing and cementing depth below the freshwater zones is determined by county, but the state requires at least 50 feet of surface casing. Alabama, California, Louisiana, Mississippi, and South Dakota regulate the minimum number of feet of casing that must be used, but not the depth below the water table.

API best practice says, "at a minimum, it is recommended that surface casing be set at least 100 ft below the deepest USDW [underground source of drinking water] encountered while drilling the

[50] 2 Colo. Reg. 404-1-317(f)

well.”[51] Only four states’ regulations (Arkansas, Maryland, Michigan, and Wyoming) meet or exceed this recommendation. Most other states require casing to be set and cemented no more than 50 feet below the water table.

Map 5. Casing and Cementing Depth Regulations



5.2.1.2 Heterogeneity

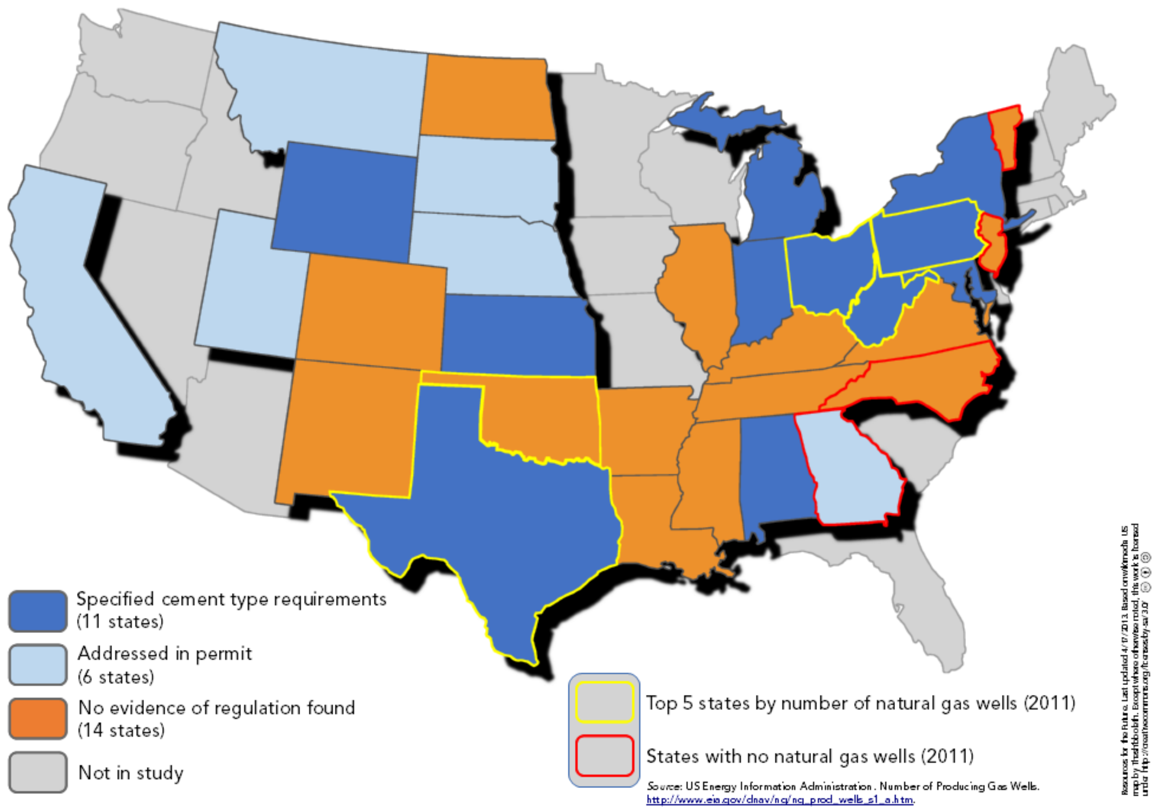
Superficially, casing and cementing depth regulations are among the most homogeneous in our study: 29 of 31 states have some form of regulation, and one of those that does not has little or no actual drilling. This homogeneity in terms of whether regulation is present, however, illustrates two other types of heterogeneity—states’ choice of regulatory tool and variation in stringency. Most states use command-and-control regulation, setting a mandatory minimum casing/cementing depth. But a few states rely on case-by-case permitting or performance standards. States may also use a hybrid approach—those with command-and-control minimums may also require deeper casing/cementing on a case-by-case basis. Among command-and-control states, specified minimum depths vary widely with no obvious geographic pattern.

5.2.2 Cement Type

Cementing practices may be regulated in terms of compressive strength, type of cement, or circulation around casing. Class A Portland cement is the most commonly required type of cement for setting casing in place. Cement types vary by well and by operator and depend on local geological and other conditions.

[51] API Guidance Document HF1, “Hydraulic Fracturing Operations- Well Construction and Integrity Guidelines,” First Edition, October 2009: Section 7.3.

Map 6. Cement Type Regulations



5.2.2.1 Regulation

Cement type regulations vary among states, and are not readily quantifiable or comparable. We therefore track only whether states have such regulations and, if so, what regulatory tool they use (see Map 6). Eleven states use command-and-control regulation specifically to regulate cement type, characteristics, and practices. Another six states address cementing in their permit processes. For the remaining 14 states, we found no evidence of cement type regulation. This last group includes three states without significant drilling activity but also a number of major gas-producing states.

Several states, including Michigan, require the cement mixture to be of a specific composition and volume that must be approved by the supervisor of the regulating agency. New York's proposed legislation specifically mandates that cement would have to conform to API Specification 10A and would have to contain a gas-block additive.

API best practice is that appropriate API standards (e.g., Specification 10A) should be consulted in the selection of cement and that "selected cements, additives, and mixing fluid should be laboratory tested in advance to ensure they meet the requirements of the well design."[52] As New York illustrates, these API standards have in some cases been explicitly incorporated into state regulation.

[52] API Guidance Document HF1, "Hydraulic Fracturing Operations- Well Construction and Integrity Guidelines," First Edition, October 2009: Section 5.2.

5.2.2.2 Heterogeneity

Cement type regulation shows few obvious geographic patterns. A block of states in the Northeast (nearly identical to the block discussed above with setback restrictions from water sources) regulates cement type with command-and-control tools. This is relatively uncommon in the rest of the country—many western states favor regulating cement with case-by-case permitting.

5.2.3 Cement Circulation

As noted above, each successive type of casing is cemented in place with cement pumped down the wellbore and up through the annulus on the outside of the casing. But cement need not necessarily be circulated all the way to the surface for each layer of casing. How much cement to circulate depends on operator practice and local conditions but is also heavily regulated by states. These regulations are different from those discussed above for casing and cementing depth. Casing/cementing depth rules (discussed in subsection 5.2.1) generally require surface casing to be run and cemented *down* to a certain distance below the water table. Cement circulation regulations for each type of casing, discussed in the following subsection, regulate how far *up* a given layer of casing must be cemented in place.

5.2.3.1 Regulation

5.2.3.1.1 Surface Casing

Twenty-eight states require surface casing, the outermost layer of casing, to be cemented all the way to the surface (see Map 7). This is the most homogeneous regulation among those we study in this report. Virginia is the only state with active gas drilling (as of 2010) that does not explicitly require fully cemented surface casing. All states that do require such cementing do so explicitly in their statutes or regulations, not as part of their permitting process.

API best practice is "that the surface casing be cemented from the bottom to the top,"[53] but where that is not possible, cementing across all USDWs is recommended. This standard combines casing/cementing depth requirements (discussed in subsection 5.2.1) and cement circulation requirements. Insofar as cement circulation is concerned, the prevailing requirement among states for cementing of surface casing to the surface matches API's recommendation of cementing to the "top."

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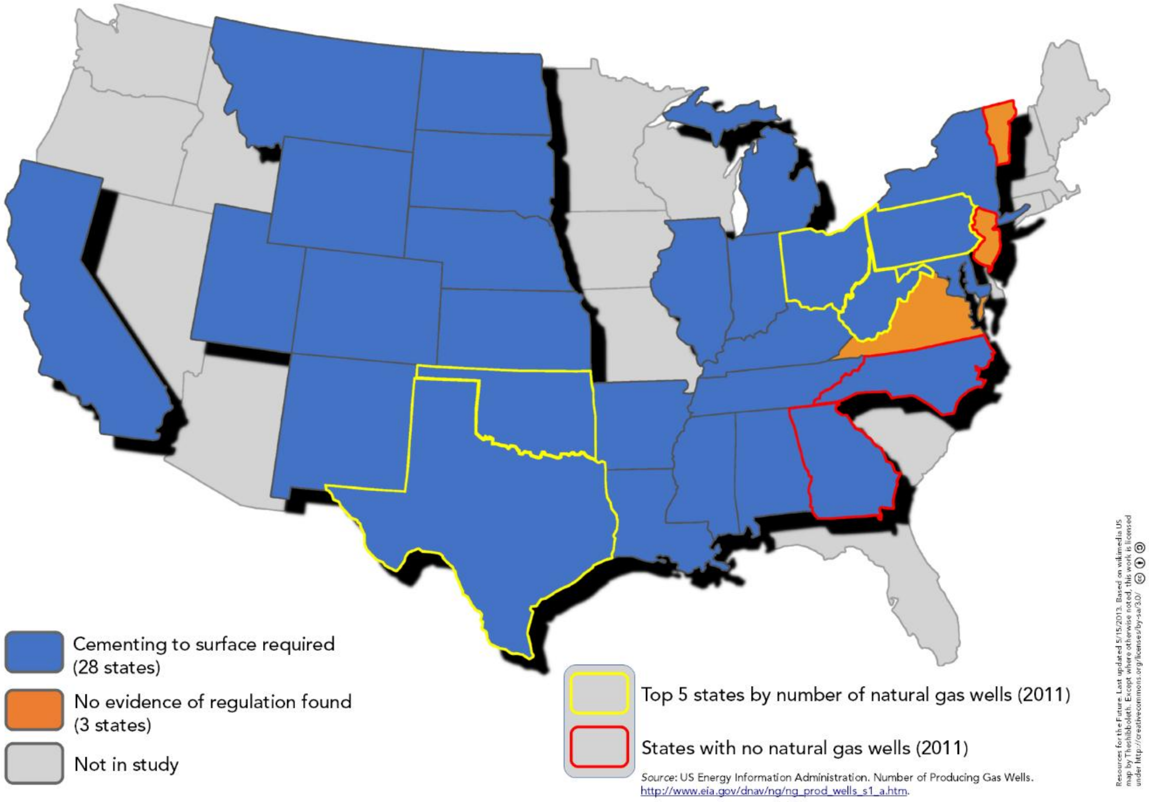
[53] API Guidance Document HF1, "Hydraulic Fracturing Operations- Well Construction and Integrity Guidelines," First Edition, October 2009: Section 7.3.

Map 7. Surface Casing Cement Circulation Regulations



5.2.3.1.2. Intermediate Casing

Cementing requirements for intermediate and production casing are much more heterogeneous. Intermediate casing is usually not mandatory, but if it is used, cementing regulations often apply (see Map 8).

Ten states use command-and control rules: in four (New York, Pennsylvania, Indiana, and Kentucky), cement must be circulated to the surface. The remaining six states specify a distance above the shoe (the bottom of the casing string) or uppermost hydrocarbon zone to which intermediate casing must be cemented. This distance ranges from 200 feet above the uppermost hydrocarbon zone (Colorado and Oklahoma) to 600 feet above the shoe (Texas).

Alabama uses a performance standard: operators are required to isolate and protect groundwater or hydrocarbon zones, but regulations do not specifically dictate how far cement must be circulated to achieve that goal.

Eight states regulate intermediate casing cementing depth via their permitting processes. The remaining 12 states do not appear to specifically regulate cementing of intermediate casing, though three of these (Arkansas, Illinois, and Mississippi) do require cementing of production casings.

API recommends that sufficient cement be circulated around the intermediate casing to isolate all USDWs and hydrocarbon zones. API best practice is “if the intermediate casing is not cemented to the surface, at a minimum the cement should extend above any exposed USDW [underground sources of drinking water] or any hydrocarbon bearing zone."[54] The four states that require cementing to the surface meet or exceed this recommendation, as does Alabama's performance standard. It is not clear how other states that regulate intermediate casing cement compare, however. The stringency of states that use permitting is impossible to observe. And it is unclear whether the height of cementing required by states that have quantitative requirements above the shoe/hydrocarbon zone are sufficient for cement to extend above any "exposed underground sources of drinking water."

5.2.3.1.3 Production Casing

Only two states (Arkansas and New York) require production casing to be cemented to the surface. Twelve states have specific regulations for how much cement must be circulated. These rules vary and are measured from similar but slightly different points (see Map 9).[55]

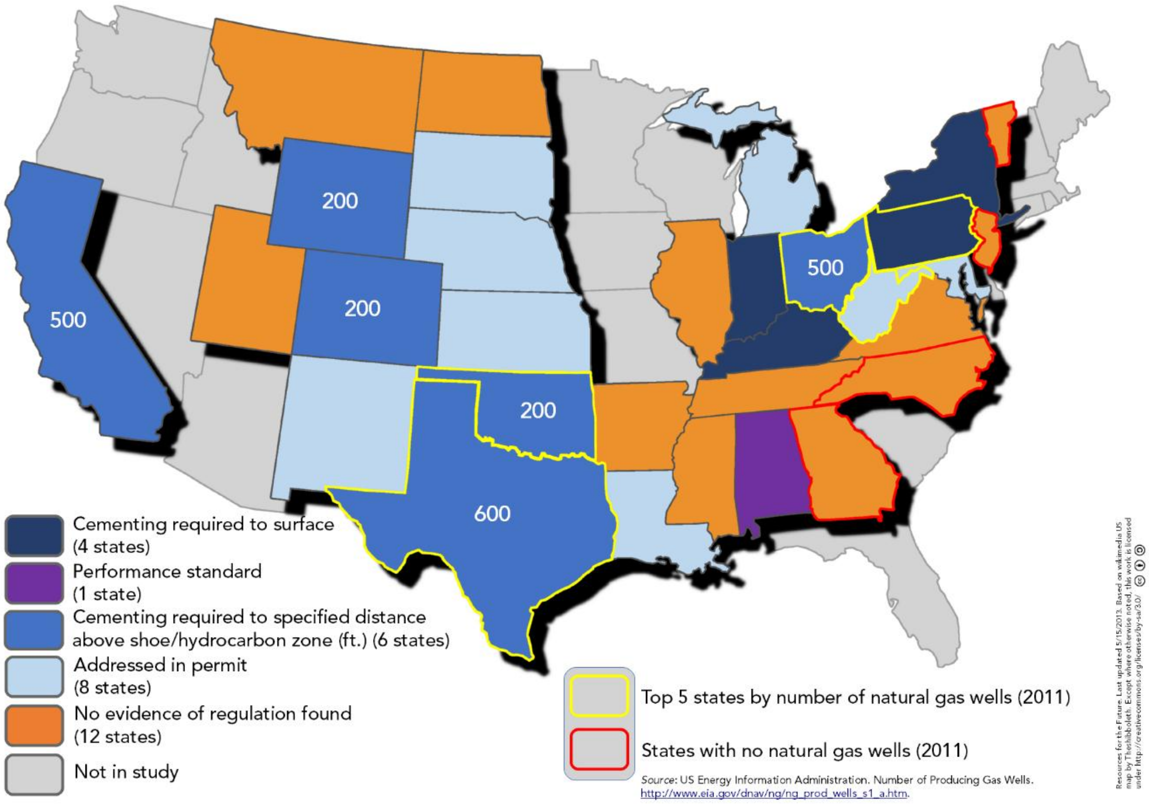
- Alabama, California, Georgia, and Louisiana stipulate that cement must reach 500 feet above the uppermost hydrocarbon zone.
- Colorado and Illinois mandate 200 and 250 feet, respectively, above the uppermost hydrocarbon zone.
- Wyoming specifies 200 feet above the trona interval (a rock layer in the local geology).
- Mississippi and North Carolina require cement to reach 500 feet above the shoe.
- Texas requires cement to reach 600 feet above the shoe. Pennsylvania mandates cement circulation 500 feet from the true vertical depth.

A further 10 states regulate cementing of the production casing in their permit processes. We found no evidence of regulation in the remaining seven states.

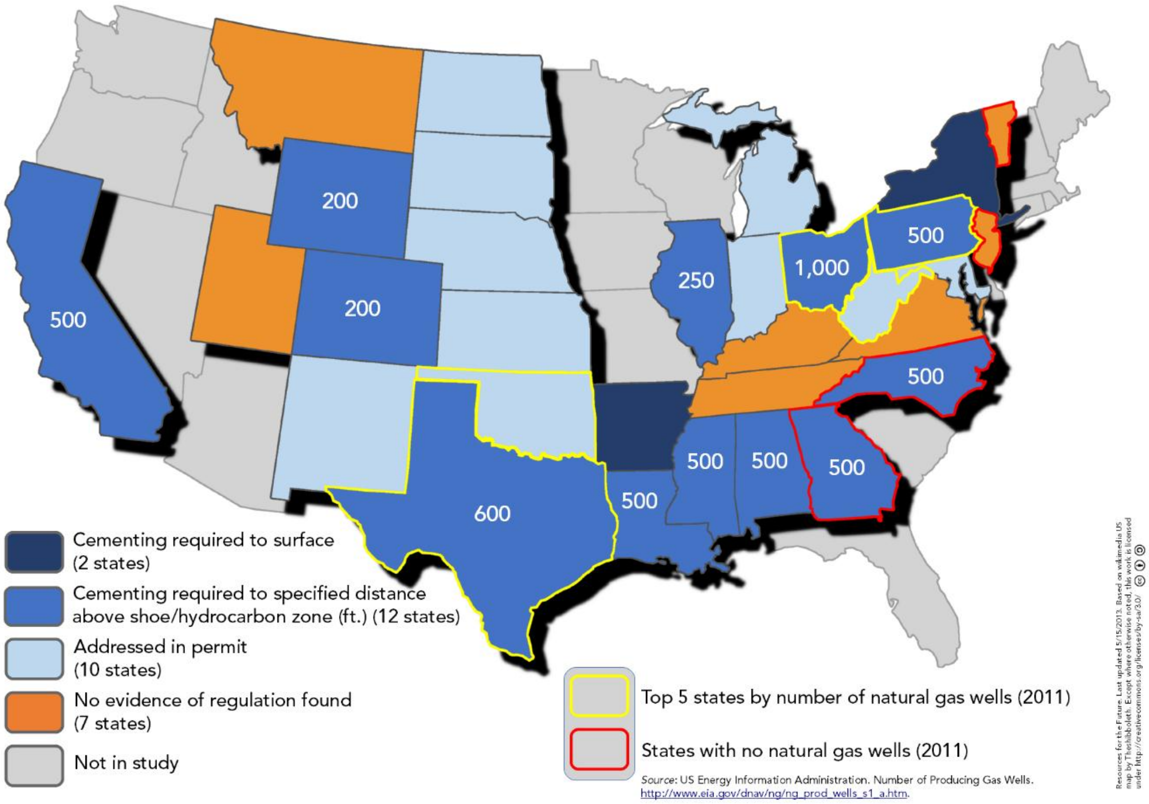
API states that best practice is to cement production casing to "at least 500 ft above the highest formation where hydraulic fracturing will be performed."[56] States that require cementing to the surface obviously meet this standard. Among states that do not require cementing to the surface but do specify a number of feet above the shoe/hydrocarbon zone, most require at least 500 feet. Only Colorado and Illinois do not (it is unclear how Wyoming's measurement from the trona interval should be compared).

[54] API Guidance Document HF1, "Hydraulic Fracturing Operations- Well Construction and Integrity Guidelines," First Edition, October 2009: Section 7.4.
[55] For purposes of our stringency analysis, we do not differentiate among these requirements.
[56] API Guidance Document HF1, "Hydraulic Fracturing Operations- Well Construction and Integrity Guidelines," First Edition, October 2009: Section 7.5.

Map 8. Intermediate Casing Cement Circulation Regulations



Map 9. Production Casing Cement Circulation Regulations



5.2.3.2 Dynamism

States have proposed several modifications to casing and cementing standards. The most common change involves pressure testing—several states have added or proposed new requirements that, prior to fracking, the well must be pressure tested to show that the cement and casing can stand the maximum pressures that will be placed on them by fracking.[57]

5.2.3.3 Heterogeneity

Surface casing cement circulation rules are among the most homogeneous in our study—the large majority of states require cementing to the surface. Intermediate and production casing regulations, on the other hand, are highly heterogeneous. Midwestern and northeastern states appear to favor cementing intermediate casing to the surface—no states in other regions require this. Otherwise, no obvious patterns appear.

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[57] See, e.g., Arkansas Oil and Gas Commission, Rule B-19, adding a new rules that surface casing must “have sufficient internal yield pressure” to withstand the maximum fracturing pressure; proposed amendments to 16 Tex. Admin. Code 3.13 et seq., explaining that a proposed new section of the code would “require that the operator pressure test the casing (or fracturing tubing) on which the pressure will be exerted during stimulation to the maximum pressure that will be exerted;” West Virginia H.B. 401, enrolled, adding a new requirement that casing have “a pressure rating that exceeds the anticipated maximum pressure to which the casing will be exposed.”

5.3 Hydraulic Fracturing

Horizontal drilling and hydraulic fracturing distinguish shale gas development from conventional gas operations. The use of relatively large quantities of water (compared to conventional gas drilling) as the primary constituent of fracturing fluid is another distinguishing feature. The details of fracking itself are not as comprehensively regulated as the drilling, casing, and cementing process is. This is not surprising because fracking is a relatively new technique (or at least relatively new in many states), whereas drilling is not—states have simply had more time to regulate the drilling process.

Regulations on water withdrawals and regarding disclosure of the composition of fracturing fluids are among the most common regulations relevant to hydraulic fracturing.

5.3.1 Water Withdrawal

Fracturing fluid is composed of water, chemicals, and a proppant (such as sand) that props the fractures open to allow gas to flow up the wellbore. Water makes up by far the largest share of this fluid, and the fracking process therefore requires several million gallons per frack job.58 If fracturing fluid is not recycled, water for each job must be withdrawn locally and trucked or piped to the site. This has led to some concern over the effect of large surface water withdrawals on ecosystems and downstream users. Water usage is particularly relevant in places where drought conditions often strictly limit water availability and appropriations. Even in water-rich areas, water withdrawals could be problematic in small streams under low flow conditions.

5.3.1.1 Regulation

Several states have discussed drafting rules about water withdrawal restrictions specific to the shale gas industry, but none has yet passed such legislation. Of the states in our study, 30 do regulate surface and groundwater withdrawals under general regulations, however (see Map 10). Some require permits for water withdrawals, others require registration and reporting, and a few require both. For purposes of our analysis, we treat both requirements as a form of permitting.

The majority of states (26) require general permits for surface and/or groundwater withdrawals. About half of these states (12) require permits for all withdrawals. The remaining 14 states require permits only for withdrawals above a specified threshold.

Eight states require registration and reporting of water withdrawals. Five of these—Illinois, Indiana, Ohio, West Virginia, and Vermont—require both a permit and reporting (and are therefore also included in the group of 26 states noted above that require permits).[59] Of the states that require reporting, only Louisiana does so for all withdrawals. The remaining seven states require reporting only for withdrawals over a specified threshold.

One state in our survey, Kentucky, exempts the oil and gas industry from water withdrawal regulations.

In addition to these permitting or reporting requirements, some states have other regulations governing water withdrawals.

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[58] Congressional Research Service, *Unconventional Gas Shales: Development, Technology, and Policy Issues*, (Washington, DC: Congressional Research Service, 2009), 7, accessed May 7, 2013, http://www.fas.org/sgp/crs/misc/R40894.pdf.

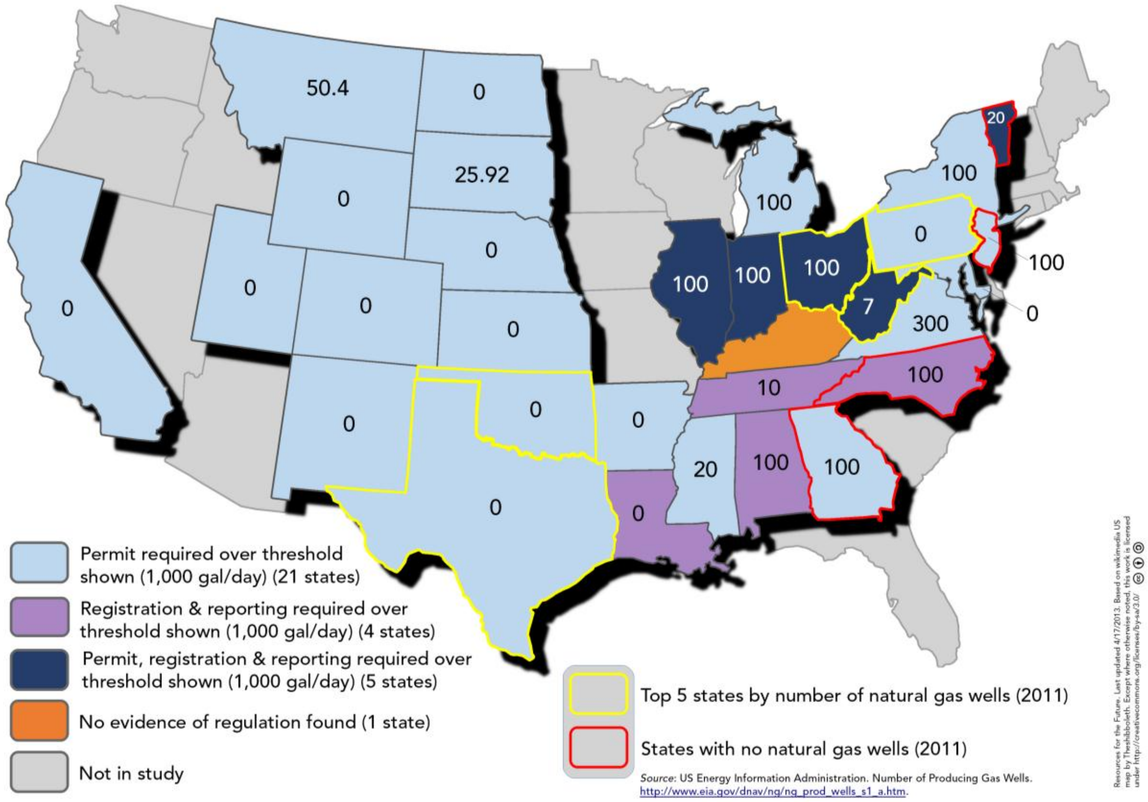
[59] Permits and registration/reporting may be required at different thresholds, or thresholds may differ for surface and groundwater; if so, we treat the lower of the two as the state threshold for purposes of our maps and statistical analyses.

- Ohio requires registration and reporting of withdrawals over 100,000 gallons per day, but does not require permits unless withdrawal is greater than 2,000,000 gallons per day.
- Pennsylvania requires a water management plan covering the full lifecycle of the water used in shale gas production, including the location and amount of the withdrawal and an analysis of the impact of the withdrawal on the body of water from which it came.
- Pennsylvania and the Susquehanna RBC require permits for any water withdrawals for fracking and operate ecosystem models that provide the basis for rejecting applications for water withdrawals that would put stress on ecosystems.
- For withdrawals of more than 210,000 gallons per month, West Virginia requires a similar water management plan that documents the source of the water withdrawal and demonstrates that its impact will be minimal.
- Louisiana recommends that groundwater used for drilling or fracking be taken from the Red River Alluvial aquifer.
- Texas requires permits for surface water withdrawals, but not for groundwater.

API best practice stipulates that "consultation with appropriate water management agencies" is a "must" and that "whenever practicable operators should consider using non-potable water for drilling and hydraulic fracturing."[60] This recommendation fits with the prevailing state practice of requiring permits for significant withdrawals—this is essentially a requirement for "consultation."

[60] API Guidance Document HF2, "Water Management Associated with Hydraulic Fracturing," First Edition, June 2010: Section 6.2.2.

Map 10. Water Withdrawal Regulations



5.3.1.2 Dynamism

Several of the water withdrawal regulations mentioned above are relatively recent additions—West Virginia added the water management plan requirement in 2011 legislation, for example[61]—and more changes may be forthcoming. The Texas legislature suggested that it may introduce legislation to include "incentivizing the recycling or reuse of flowback water."[62]

5.3.1.3 Heterogeneity

The clearly prevailing rule among states is to require permits for at least some water withdrawals. States in the East, however, generally allow withdrawals below a certain threshold without a permit (Pennsylvania is the only exception), whereas most states in the West require permits for *any* withdrawal.

[61] West Virginia. H.B. 401, enrolled.

[62] House Research Organization, *Topics for the 83rd Legislature* (Austin, TX: Texas House of Representatives, December 19, 2012), 14, accessed May 7, 2013, http://www.hro.house.state.tx.us/pdf/focus/Topics83-1.pdf.

5.3.2 Fracturing Fluid Disclosure

The federal Safe Drinking Water Act (SDWA) authorizes state regulation of underground fluid injection, under EPA guidance.[63] Among other requirements, application of the SDWA to fracturing fluids would have required "inspection, monitoring, recordkeeping, and reporting" by state regulators.[64] In practice, this probably would have required the disclosure of fracturing fluid composition. In 2005, however, Congress amended the SDWA to exclude fracturing fluids other than diesel fuel.[65] Fracturing fluid disclosure has since become a controversial issue, with environmental groups (and some in industry) calling for states to require disclosure independent of federal law.[66] Many states have done so. Most rely on a web-enabled database, FracFocus, which was developed with US Department of Energy funding. The US Department of the Interior also has issued draft rules requiring fracturing fluid disclosure for wells drilled on federal lands,[67] and EPA has indicated that it will require disclosure under the Toxic Substances Control Act.[68]5.3.2.1 Regulation

Of the states surveyed, just under half (15) currently require some form of fracturing fluid disclosure (see Map 11). The level of required disclosure detail to regulators and to the public differs across states. Not all states require disclosure of all chemicals used, defaulting instead to those already required by the Occupational Safety and Health Administration on material safety data sheets (MSDS). The Occupational Safety and Health Administration requires MSDS forms only for hazardous chemicals stored in quantities of 10,000 pounds or more. MSDS also do not detail components of the named material. For example, Halliburton has posted an MSDS for "frac fluid with additives" on its website for disclosure purposes, without listing what those additives are.[69] Some stakeholders argue that limiting disclosure for fracturing fluids to MSDS data is insufficient because of the lack of ingredient data, the exemptions provided, and the number of chemicals used that are not listed as hazardous even though they may endanger human and environmental health.[70]

Some state rules have other exemptions, including exemptions for trade secrets. All states with chemical disclosure requirements provide trade secret exemptions for chemicals considered "confidential business information."

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[63] See Safe Drinking Water Act (SDWA) §1421.
[64] *Id* at §1421(b)(1)(C).
[65] *Id* at §1421(d).
[66] For instance, "Members of America's Natural Gas Alliance are committed to transparency and support public disclosure of the additives used in hydraulic fracturing through Fracfocus.org." ("Response to Harvard's 'Legal Fractures in Chemical Disclosure Laws'" America's Natural Gas Alliance, 13 May 2013.) and "Full public disclosure of chemicals and other fracking information is critical to protect public health in a number of ways." (Mall, Amy. "New NRDC Analysis: State Fracking Disclosure Laws Fall Painfully Short."*Switchboard*. Natural Resources Defense Council, 26 July 2012.)
[67] Bureau of Land Management, "Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands," 43 Federal Register 3160 (May 2013).
[68] Letter from Stephen A. Owens, Assistant Administrator, U.S. Envtl. Protection Agency, to Deborah Goldberg, EarthJustice, Nov. 23, 2011.
[69]See Mike Soraghan, *In Fracking Debate,' Disclosure' Is in the Eye of the Beholder*, New York Times (June 21, 2010), www.nytimes.com/gwire/2010/06/21/21greenwire-in-fracking-debate-disclosure-is-in-the-eye-of-19087.html?pagewanted=1. This information no longer appears to be listed on Halliburton's website, however.
[70] The Wilderness Society, *Disclosure of Hydraulic Fracturing Fluids: Are States Doing a Good Enough Job?* updated April 2011, accessed May 7, 2013, http://www.shalegas.energy.gov/resources/tws_state_chemical_disclosure_requirements.pdf; Theo Colborn, Carol Kwiatkowski, Kim Schultz, and Mary Bachran, "Natural Gas Operations from a Public Health Perspective," *Human and Ecological Risk Assessment: An International Journal* 17, no. 5 (2011): 1039–1056; Nicholas Kusnetz, "Critics Find Gaps in State Laws To Disclose Hydrofracking Chemicals," *ProPublica*, June 20, 2011, accessed May 7, 2013, http://www.propublica.org/article/critics-find-gaps-in-state-laws-to-disclose-hydrofracking-chemicals.

Some states also require disclosure of additive volume and concentration. Two examples are Pennsylvania, which requires the disclosure of the percentage by volume of each additive in the stimulation fluid, and Arkansas, which requires additives to be expressed as a percentage by volume of the total hydraulic fracturing fluids, *and* of the total additives used. Some states also require operators to categorize their disclosures by additive type.[71]

Four states (California, Illinois, Michigan and New York[72]) have proposed disclosure requirements (in Michigan's case, the proposal would strengthen existing requirements). Michigan currently requires operators to submit an MSDS and volume report for each chemical used if they are using more than 100,000 gallons of total fluids. The proposed rule would require operators to disclose the type and volume of base fluid, the trade name and supplier of each additive used in the fracturing fluid, the list of chemical ingredients contained in each additive, and the associated Chemical Abstracts Service (CAS) number. This information would have to be submitted with the permit application before fracking could take place.

Rarely, states regulate fracturing fluids beyond mere disclosure. Wyoming, for example, requires prior approval for use of benzene, toluene, ethylbenzene, and xylene (BTEX) compounds.

API suggests that operators be prepared to disclose information on chemical additives and their ingredients and that "the best practice is to use additives that pose minimal risk of possible adverse human health effects to the extent possible in delivering needed fracture effectiveness."[73]

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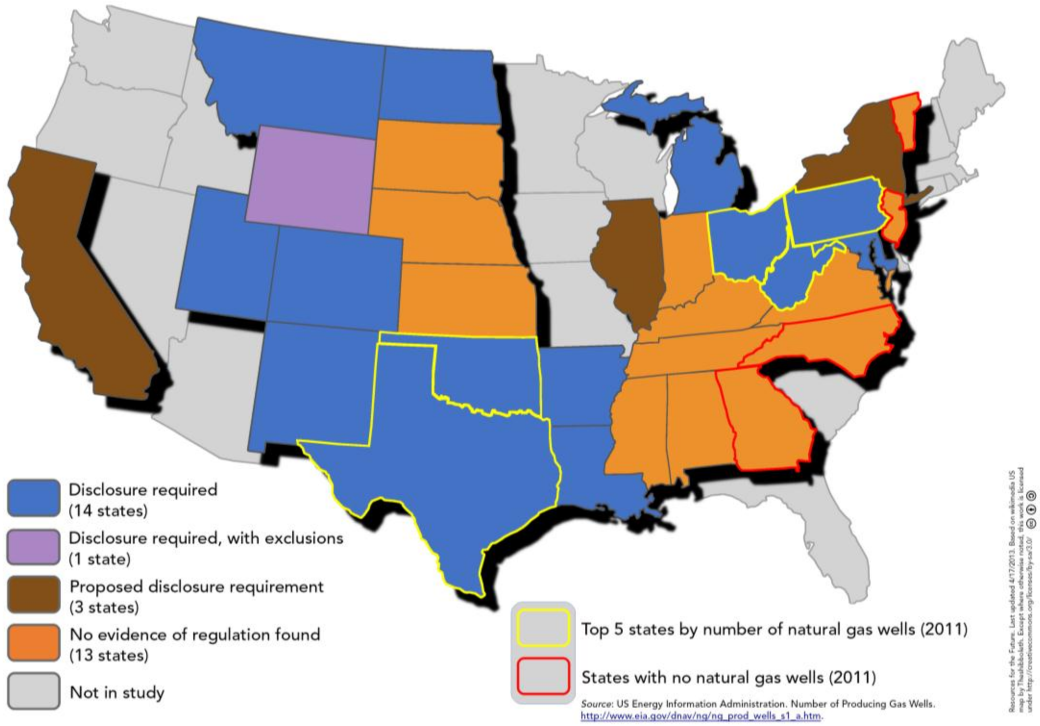
[71] Additive types include, for example, acid, biocide, breaker, corrosion inhibitor, crosslinker, demulsifier, friction reducer, gel, iron control, oxygen scavenger, pH-adjusting agent, scale inhibitor, proppant, or surfactant.

[72] Note that this discussion is an exception to our general practice of treating New York's proposed regulatory package as if it had been implemented. Because for this regulatory area we specifically identify other states with proposed rules, it would be misleading to characterize New York's proposal as we do elsewhere.

[73] API Guidance Document HF2, "Water Management Associated with Hydraulic Fracturing," First Edition, June 2010: Section 5.3.3.

Map 11. Fracking Fluid Disclosure Requirements



5.3.2.1 Dynamism

The field of chemical disclosure regulation is the most rapidly changing area in shale gas regulation. Between 2010 and 2012, at least 15 states enacted requirements that operators disclose the fracturing chemicals used at sites.[74] Some states also have anticipated further regulatory changes. Colorado, for example, which requires disclosure through the FracFocus website, provides that operators must use alternative electronic forms if FracFocus does not allow sorting by geographic area, chemical ingredient, and other factors by 2013.[75]

5.3.2.2 Heterogeneity

Setting aside the differences in scope and detail among states' disclosure rules (which we do not study in any detail), fracturing fluid disclosure in some form appears to be emerging as a prevailing rule among states. The majority (19), including all the major gas-producing states, have rules proposed or in place. Given the relatively recent emergence of large-scale hydraulic fracturing, this indicates a relatively rapid pace of regulatory change. It is possible, therefore, that the states without disclosure requirements will follow the lead of the major producers and implement such rules as their drilling and production activity increases.

[74] Hannah Wiseman, "The Private Role in Public Fracturing Disclosure and Regulation," *Harvard Business Law Review Online* 3 (2013): 49–66, accessed May 9, 2013, http://www.hblr.org/2013/02/the-private-role-in-public-fracturing-disclosure-and-regulation/.
[75] 2 Colo. Code Regs. § 404-1:205A(b)(3)(B) (Westlaw 2012).

5.4 Wastewater Storage and Disposal

From 10 to 50 percent of the fracturing fluid will eventually flow back up and out of the wellbore, depending on the geological characteristics of the play and well.[76] These flowback fluids, as well as produced fluids from the formation itself (sometimes referred to as formation water) require storage and disposal. We generally refer to these fluids as "wastewater," though they differ greatly in composition and toxicity, and may in fact be recycled. Failure to properly store, recycle, or dispose of wastewater increases the risk of spills or leaks that can lead to surface or groundwater contamination. This subsection reviews regulation of these practices. Note that although the volume of flowback fluids make storage and disposal practices most significant during and immediately after the fracking process, water may be produced from the formation on an ongoing basis (though usually in much smaller volumes) and must be removed from gas before it can be transported and sold.

5.4.1 Fluid Storage Options

Options available to operators for temporary storage of wastewater vary greatly among states and within each state depending on the type and composition of wastewater. Different wastes have different viscosity, toxicity, and other characteristics and are therefore regulated differently. Fluids are most commonly stored in open pits or closed tanks. Some state regulations mention storage of wastewater in ponds, sumps, containers, impoundments, and ditches, but all of these can be considered subtypes of pits or tanks.

Fluid storage needs vary over the course of the shale gas development process. Fracturing fluids must be stored before use, and the postfracturing wastewater, including flowback fluids and produced fluids, must also be stored before disposal. There are many different types of pits, including permanent and temporary pits or, more specifically, completion pits, reserve pits, slush or mud pits, sediment pits, test pits, circulation pits, workover pits, burn pits, settling pits, emergency pits, haul-off pits, holding pits, drilling pits, earthen pits, water condensate pits, evaporation pits, and disposal pits. States vary in how they define and regulate each type of pit. Each type of pit is approved to accept certain types of fluids, and not all types of fluids can be stored in pits in a given state.

Importantly, there is a potentially significant difference between allowing drilling muds to be stored in pits and allowing flowback or produced fluids to be stored in pits. Drilling muds do not have the same chemical mixture as flowback and produced fluids[77] and, according to our expert survey, drilling mud spills are not a high priority, though flowback fluid, produced fluid, and fracturing fluid spills are.[78]

5.4.1.1 Regulation

For purposes of our analysis, we grouped state fluid storage regulations into four groups (see Map 12). In the first group, 10 states require sealed storage (in tanks) for at least some types of fluid (no states require tank storage for all types of fluid). In the second group of 16 states, we found no evidence of regulations requiring sealed tank storage for any fluids—we interpret this to mean that these states allow any and all fluid types to be stored in open pits In the third group, three states (Ohio,

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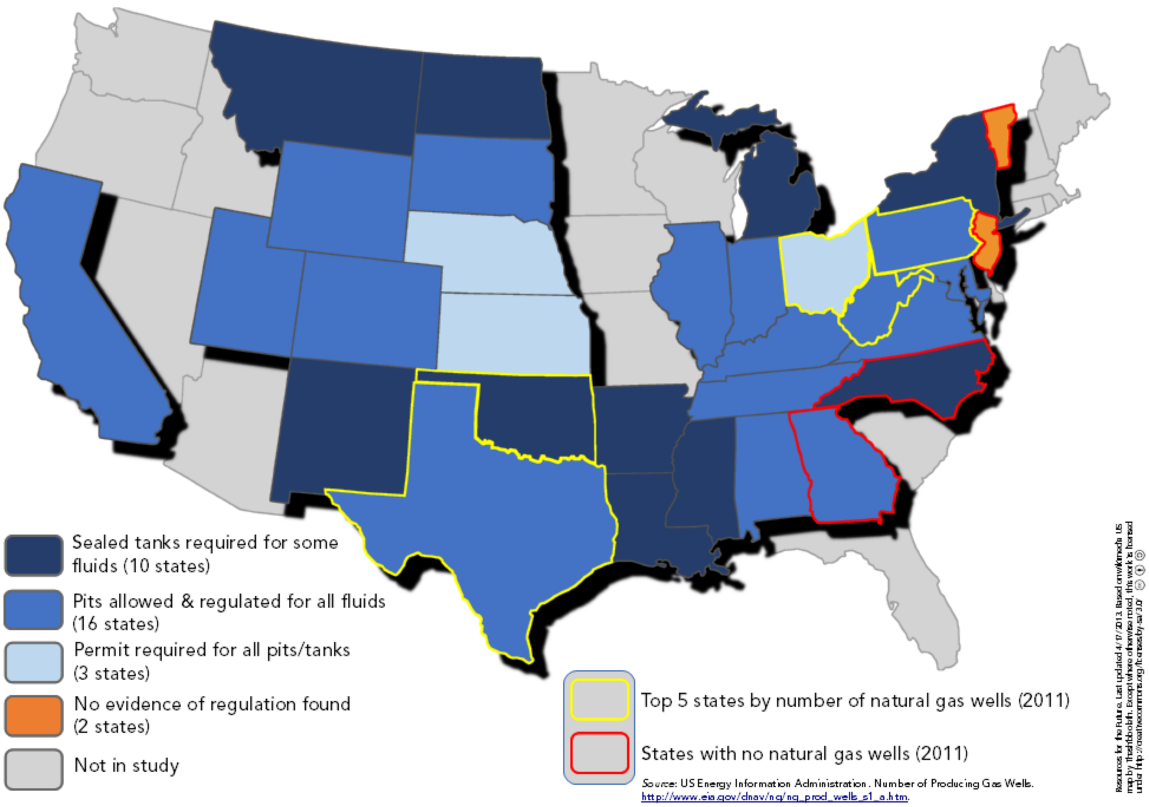
[76] Yoxtheimer, Dave. "Shale Gas Flowback Water Treatment, Reuse and Disposal," presentation slides, Penn State, Marcellus Center for Outreach and Research, no date.

[77] "Waste Management of Cuttings, Drilling Fluids, Hydrofrack Water and Produced Water," New York State Water Resources Institute, updated March 21, 2012, accessed May 9, 2013, http://wri.eas.cornell.edu/gas_wells_waste.html.

[78] Alan Krupnick, et al. *Pathways to Dialogue*.

Nebraska, and Kansas) require a specific permit application for fluid storage. Regulators may require some fluids to be stored in sealed tanks as a condition of permit approval, but this cannot be determined from the regulations alone. All 29 states across these three groups regulate open-pit storage in various ways, some of which—liner thickness and freeboard—are tracked as separate regulatory elements in our analysis. The remaining two states, New Jersey and Vermont, do not mention pits or sealed tank storage in their regulations.

Map 12. Fluid Storage Options



As noted above, state regulations vary greatly depending on what type of fluid is being stored. For example:

- Michigan allows pits to be used only for drilling fluids, muds, and cuttings; tanks must be used for produced water, completion fluids, and other liquid wastes, and in all areas zoned residential.
- Mississippi allows temporary brine storage pits only if "no other means of storing or disposing of salt water is available."[79]
- Kentucky (among other states) distinguishes between the type of pit that may be used to store flowback and produced fluids (holding pits) versus that which may be used for other drill fluids, such as drilling muds (drilling pits).

[79] Statewide Rules and Regulations 45(III)(E)(2)

- New Mexico requires permanent pits for storing produced water or brine but allows temporary pits for storing drilling and workover fluids.
- Oklahoma allows the use of pits so long as the contents do not have chloride concentrations greater than 10,000 milligrams per liter.
- New York's proposal requires flowback water to be stored in water-tight tanks, whereas other wastes could be stored in pits.

API best practice stipulates that "completion brines and other potential pollutants should be kept in lined pits, steel pits, or storage tanks."[80] Though our analysis does not differentiate among fluid types, this standard, like 16 states' regulations, does not make fine distinctions among wastewater types, and in principle allows all fluids to be stored in open pits.

5.4.1.2 Heterogeneity

Geographically, we did not find any obvious patterns for fluid storage options across the nation. A clump of states in the Southwest only regulate pits, but states that allow pits and tanks are dominant and are spread around the country. Many of the major gas-producing states only mention pits in their regulations, though these states presumably allow sealed tank storage for most fluids, and may regulate sealed storage systems through their permit processes.

5.4.2 Freeboard

Beyond the question of whether pits are allowed for some or all wastewater, states regulate specific characteristics of those pits with rules aimed at reducing the likelihood of spills or leaks. Two of the most common and most important such regulations apply to pit liners and freeboard—the difference between the top of a pit and its maximum fluid level. Freeboard is important for preventing overflow of fluids, particularly during and after intense rain.

5.4.2.1 Regulation

Of the states surveyed, 17 have freeboard regulations, requiring from one to three feet of freeboard (see Map 13). Montana's requirement of three feet of freeboard applies only to earthen pits or ponds that receive produced water containing more than 15,000 parts per million total dissolved solids in amounts greater than five barrels per day on a monthly basis. Georgia addresses freeboard in its permit process. The remaining 12 states do not appear to regulate freeboard, though 2 of them—Vermont and New Jersey, both states without any natural gas wells as of 2011—have no regulations on fluid storage options, as discussed in the previous section.

The specifics of freeboard rules differ among states, as shown in the following examples.

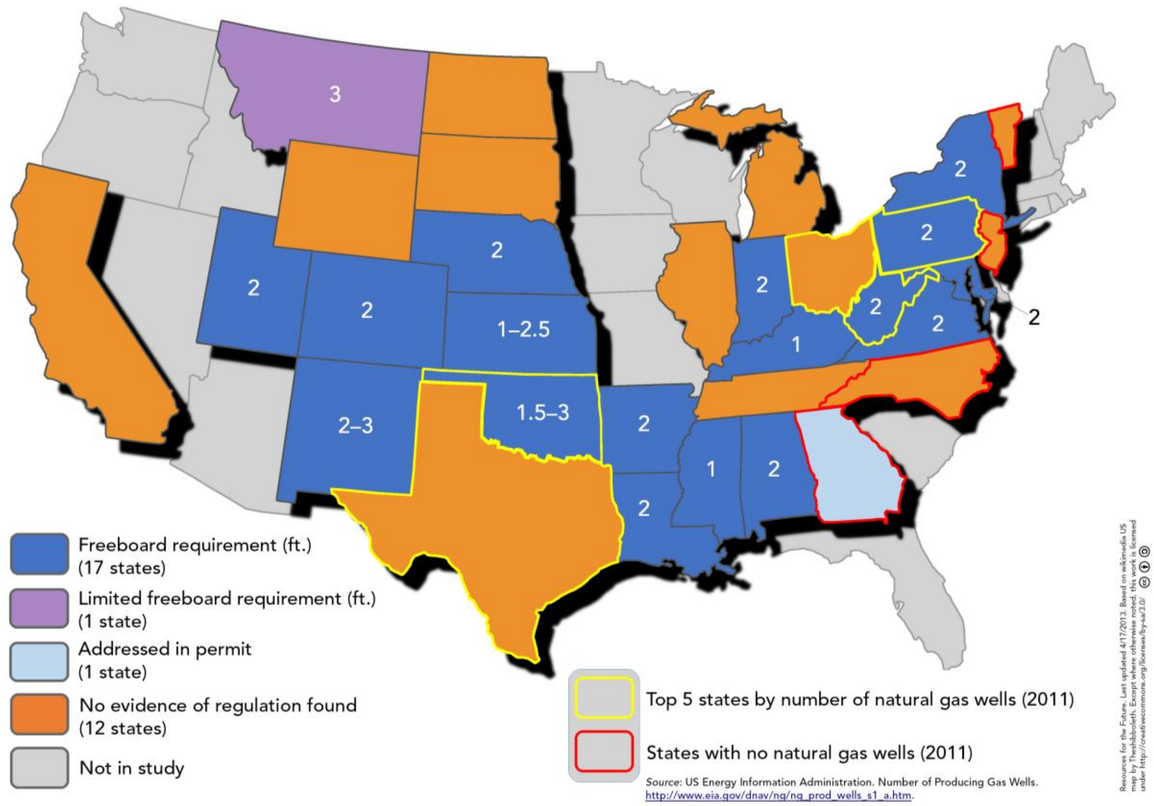
- New Mexico freeboard rules are different for permanent (three feet) and temporary (two feet) pits.
- Kansas requires one foot of freeboard for drilling, workover, burn, and containment pits, but 30 inches of freeboard for emergency and settling pits.

[80] API Recommended Practice 51R, "Environmental Protection for Onshore Oil and Gas Production Operations and Leases," First Edition, July 2009: Section 6.1.6.

- Oklahoma requires 1.5 feet of freeboard for temporary pits, 2 feet of freeboard for non-commercial pits, and 3 feet of freeboard for pits capable of holding more than 50,000 barrels.

API best practice is that pits should be constructed with sufficient freeboard "to prevent overflow under maximum anticipated operating requirements and precipitation."[81] It is hard to determine whether state regulations meet this recommendation because "operating requirements and precipitation" vary, but it would take a lot of rain to overtop a pit with the most common freeboard standard of two feet. Spills or accidentally overfilled pits may also be a risk, however.

Map 13. Freeboard Requirements



5.4.2.1 Dynamism

It appears that most states have not changed freeboard requirements in recent years, although several have updated other requirements for surface pits, including the acceptable location of pits, required liners, and the timing of pit closure. West Virginia's legislature has generally directed the secretary of the Department of Environmental Protection to "report to the Legislature on the safety of pits and impoundments utilized," and, if necessary, to propose new rules for pit safety, monitoring, and design.[82]

[81] API Recommended Practice 51R, "Environmental Protection for Onshore Oil and Gas Production Operations and Leases," First Edition, July 2009: Section 8.3.1.
[82] W. Va. Code § 22-6A-23 (2011).

5.4.2.2 Heterogeneity

We found no obvious pattern in the geographical distribution of freeboard requirements. One might expect eastern states with greater precipitation to be more likely to regulate freeboard, and to require more of it, than dry states in the Southwest. But this does not appear to be the case. Because freeboard is primarily useful in preventing overflow due to stormwater, the size and rate of high-precipitation events may be a larger source of risk than the total annual rainfall.

5.4.3 Pit Liners

Pit liners prevent fluids from seeping into the ground and potentially contaminating groundwater.

5.4.3.1 Regulation

Of the states surveyed, 21 explicitly require pit liners for at least some types of pits in their regulations or statutes (see Map 14). Four states (Georgia, Texas, Indiana, and Montana) regulate pit liners in their permit processes.[83] Of the states that require liners, 11 specify a minimum liner thickness, varying from 10 mils (Virginia) to 40 mils (Utah), with a national average of 22.4 mils. Wyoming requires liners only “if necessary” to prevent contamination of surrounding ecosystems—we interpret this as a discretionary standard.[84]

State pit liner requirements, like those for freeboard or open pits versus closed fluid storage, differ depending on the type of fluid being stored and other conditions, as shown in the following examples.

- Kentucky requires liners only for holding pits that store produced fluids; drilling pits (which do not store produced fluids) do not require liners.
- Arkansas regulates several kinds of pits with different specifications for each: reserve pits, completion pits, and mud pits must normally be lined with a synthetic liner of at least 20 mils thickness, but pits used to store postdrilling produced water and frack flowback fluid must be lined with a clay liner and a synthetic liner of at least 40 mils thickness.

States often have a variety of other regulations for pit construction, including pit wall slopes, foundation standards, anchor trenches, liner seams, and liner permeability. In addition, they frequently regulate the amount of time that certain fluids may remain in pits before being disposed of. Many states also have specific regulations on liner materials. Kansas, for example, allows pits to be lined with natural clay liners, soil-mixture liners, recompacted clay liners, or manufactured synthetic liners.

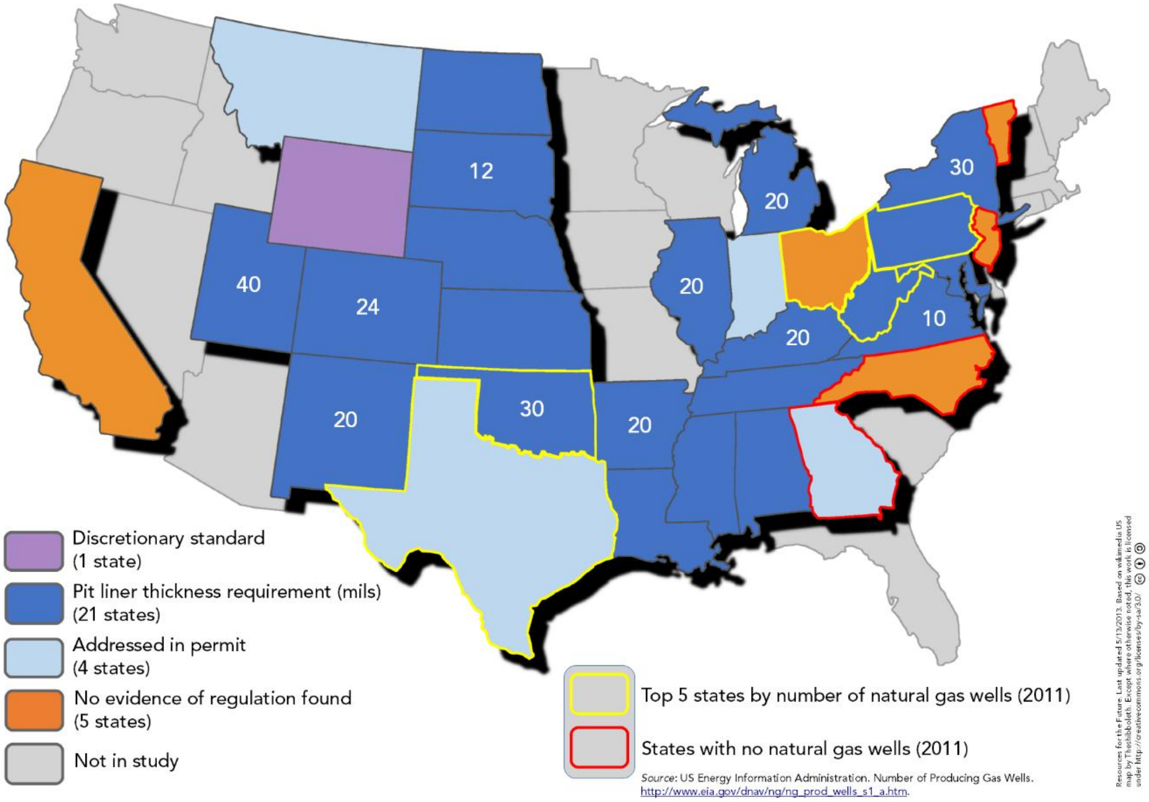
API best practice is that “depending upon the fluids being placed in the impoundment, the duration of the storage and the soil conditions, an impound lining may be necessary to prevent infiltration of fluids into the subsurface.”[85] This recommendation lacks sufficient precision to meaningfully compare to state regulations that explicitly require pit liners.

[83] Montana regulations also specifically require liners for earthen pits or ponds that contain fluids with more than 15,000 parts per million total dissolved solids or that receive more than five barrels of fluid per day on a monthly basis.

[84] We interpret this as a discretionary standard in that it leaves to operator discretion the conditions under which a liner is required, without any apparent enforceable requirement. It is possible, however, that the decision of whether to line pits is reviewed as part of Wyoming’s permit process.

[85] API Guidance Document HF2, “Water Management Associated with Hydraulic Fracturing,” First Edition, June 2010: Section 6.3.2.

Map 14. Pit Liner Requirements



5.4.3.1 Dynamism

As with freeboard, it appears that few states have changed specific pit lining requirements. States have, however, changed a variety of other regulations associated with pits. Ohio, which previously provided that "pits" may be used for wastes at well sites, added that "pits or steel tanks shall be used as authorized by the chief [of the Division of Oil and Gas Resources Management]," and added that these may be used for wastes produced in connection with "well stimulation" in addition to drilling, reworking, reconditioning, plugging back, or plugging operations[86]. Ohio also previously provided that "[n]o pit or dike shall be used for the ultimate disposal of brine" and, in 2010, its legislature appeared to anticipate the need to clarify that other oil and gas drilling substances also may not be disposed of in pits[87]. Substitute Senate Bill 165 added language clarifying that no dike or pit shall be used for the ultimate disposal of "other liquid waste substances."[88] Colorado also added a provision that "at the time of initial construction," produced water pits "shall be located not less than two hundred (200) feet from any building unit."[89]

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[86] Ohio Rev. Code Ann. § 1509.22(c)(3)
[87] Ohio Rev. Code Ann. § 1509.22(c)(7)
[88] Ohio Rev. Code § 1509.22(C)(4), text described added by Substitute S.B. 165 (signed by Governor Strickland 2010).
[89] 2 Colo. Code Regs. § 404-1:605f, added by COGCC final rule amendments, December 17, 2008.

Some pits are used as spill prevention and control devices rather than to directly store waste. These pits may be placed under tanks as secondary containment, for example, to capture any fluid spilled. Ohio, which previously provided that dikes or pits used for spill prevention and control "shall be constructed and maintained to prevent the escape of brine" and shall be kept "reasonably free of brine," added that the pits shall be constructed to prevent the escape of, and shall be kept reasonably free of "crude oil" as well.[90] Pennsylvania added a new requirement that, for unconventional well sites, "[a]reas where any additives, chemicals, oils or fuels are stored must have sufficient containment capacity to hold the volume of the largest container stored in the area plus 10 percent to allow for precipitation," unless the tank has individual secondary containment.[91] It also added a new requirement that containment structures at unconventional well sites "[b]e sufficiently impervious and able to contain spilled waste material until it can be removed or treated."[92]

5.4.3.2 Heterogeneity

We found no obvious geographical patterns in the distribution of pit liner requirements, other than the fact that three of four states without significant development lack regulation in this area.

Pit or tank storage is usually temporary. Long-term or permanent disposal is a separate challenge, and is subject to different state regulations. The wide variety of fluids that must be disposed of make both the disposal process and an analysis of its regulation difficult. States offer a variety of disposal options for wastewater (including flowback and produced waters), drilling fluids, muds, and cuttings. One option for flowback fluids is to recycle them for use in future frack jobs. Recycling is frequently not discussed in state regulations, but we assume that it is legal in all states. Other than recycling, options for fluid disposal include underground injection, treatment at a disposal facility, evaporation ponds/pits, land application, or discharge to surface water. The following analysis describes which of these options are available in different states.

One important caveat is that regulations may restrict disposal options to certain types of wastewater or other fluids—a state is shown as allowing a method to be used if its regulations allow it for any type of fluid byproduct of shale gas development. Some states, however, do not differentiate between which kinds of wastes are covered by each rule. In many cases, permits are required prior to waste disposal.

5.4.4 Underground Injection

Some wastes may be injected deep underground in wells drilled for that purpose.

5.4.4.1 Regulation

Underground injection of waste fluids is allowed at the state level in 30 of the states studied (see Map 15). All of these states, however, regulate the practice in some way. Local geology may make underground injection impractical, however (Pennsylvania is a notable example).[93] The details of underground injection restrictions and regulations vary among states. For example:

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[90] Ohio Rev. Code § 1509.22(C)(7), text described added by Substitute S.B. 165, signed by Governor Strickland 2010.
[91] 58 Pa. C.S. § 3218.2(d), text described added by H.B. 1950, approved by Governor Corbett February 14, 2012.
[92] *Id*.
[93] Charles Abdalla, Joy Drohan, Kristen Saacke Blunk, and Jessie Edson, *Marcellus Shale Wastewater Issues in Pennsylvania—Current and Emerging Treatment and Disposal Technologies* (University Park, PA: Penn State Extension, 2011).

- Only North Carolina expressly prohibits underground injection of fluids produced in the extraction of oil and gas.
- Montana *requires* underground injection of all fluids with more than 15,000 parts per million total dissolved solids (TDS).
- Ohio *requires* brine to be disposed of by injection into an underground formation unless the board of the county commissioners permits surface application to roads, streets, and highways.

Three states allow underground injection but have recently issued limited or local moratoria because of increased seismic activity linked to shale gas fluid disposal. As a result, some deep injection wells have been closed while further research is conducted.[94]

- Arkansas has a moratorium on deep injection in a 600-square-mile area of the state where a fault may have been activated by wastewater injections in the area.
- Ohio has recently followed a similar course of action, temporarily closing down several injection wells (out of more than 100) in an area where seismic activity has occurred.
- Fort Worth, Texas, has a ban on deep injection wells.[95]

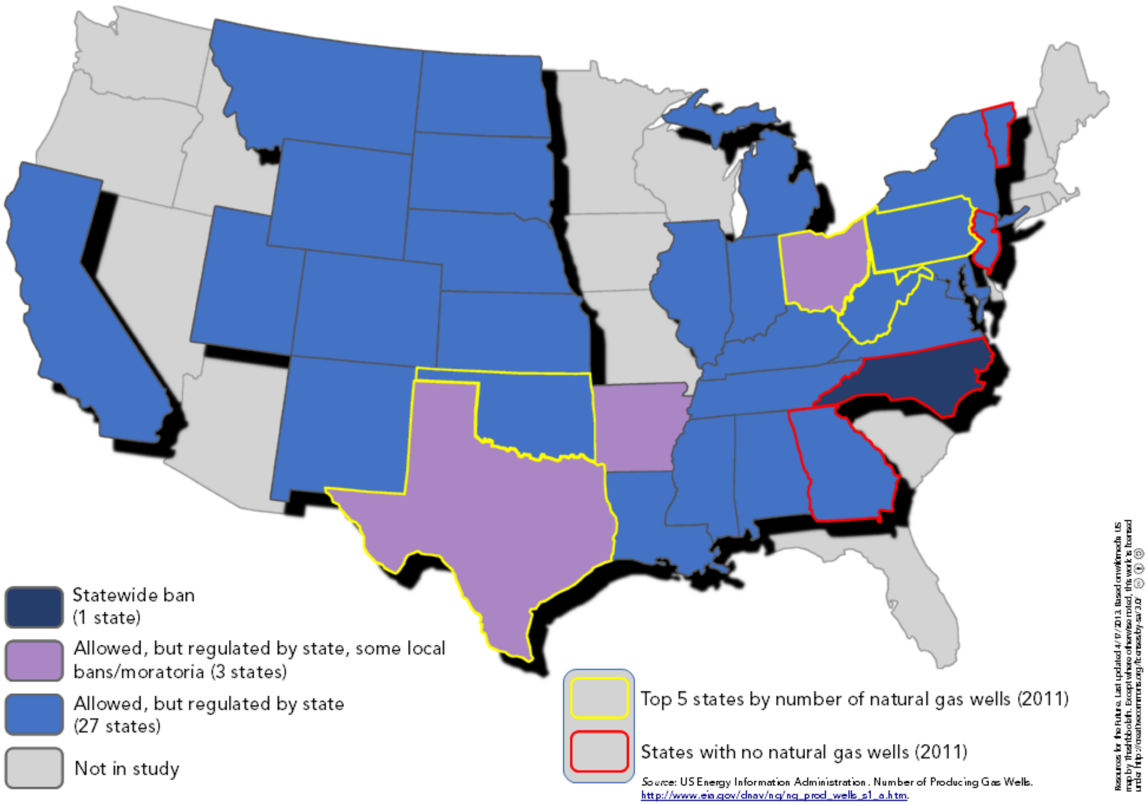
API says that "disposal of flow back fluids through injection, where an injection zone is available, is widely recognized as being environmentally sound, is well regulated, and has been proven effective."[96] This recommendation is echoed by the 30 states that (limiting regulations and local or temporary moratoria aside) allow the practice.

5.4.4.2 Dynamism

As introduced above, some states have begun to modify general injection well practices by, for example, temporarily closing certain wells. Some states also have begun to change specific injection well requirements. Colorado added a financial assurance requirement for "surface facilities and structure appurtenant to the Class II commercial injection well," under which operators must provide $50,000 for each facility.[97] Ohio similarly introduced an injection well fee of "[f]ive cents per barrel of each substance that is delivered to a well to be injected in the well" when the substance is produced "within the regulatory district in which the well is located" or an adjoining district; the fee increases to "[t]wenty cents per barrel" when the injected fluid is produced elsewhere. The fee may not apply to more than 500,000 barrels of substance per injection well annually.[98]

[94] Mike Soraghan, "Drilling Waste Wells Exempt from Earthquake Testing Rules," *EnergyWire*, March 22, 2012.
[95] Bill Hanna, "Fort Worth City Council Votes To Ban Saltwater Disposal Wells," *Star-Telegram.com,* April 2012.
[96] API Guidance Document HF2, "Water Management Associated with Hydraulic Fracturing," First Edition, June 2010: Section 7.2.
[97] 2 Colo. Code Regs. § 404-1:702, text described added by COGCC, final rule amendments, December 17, 2008.
[98] Ohio Rev. Code § 1509.22(B), text described added by Substitute S.B. 165 (signed by Governor Strickland 2010).

Map 15. Underground Injection Requirements

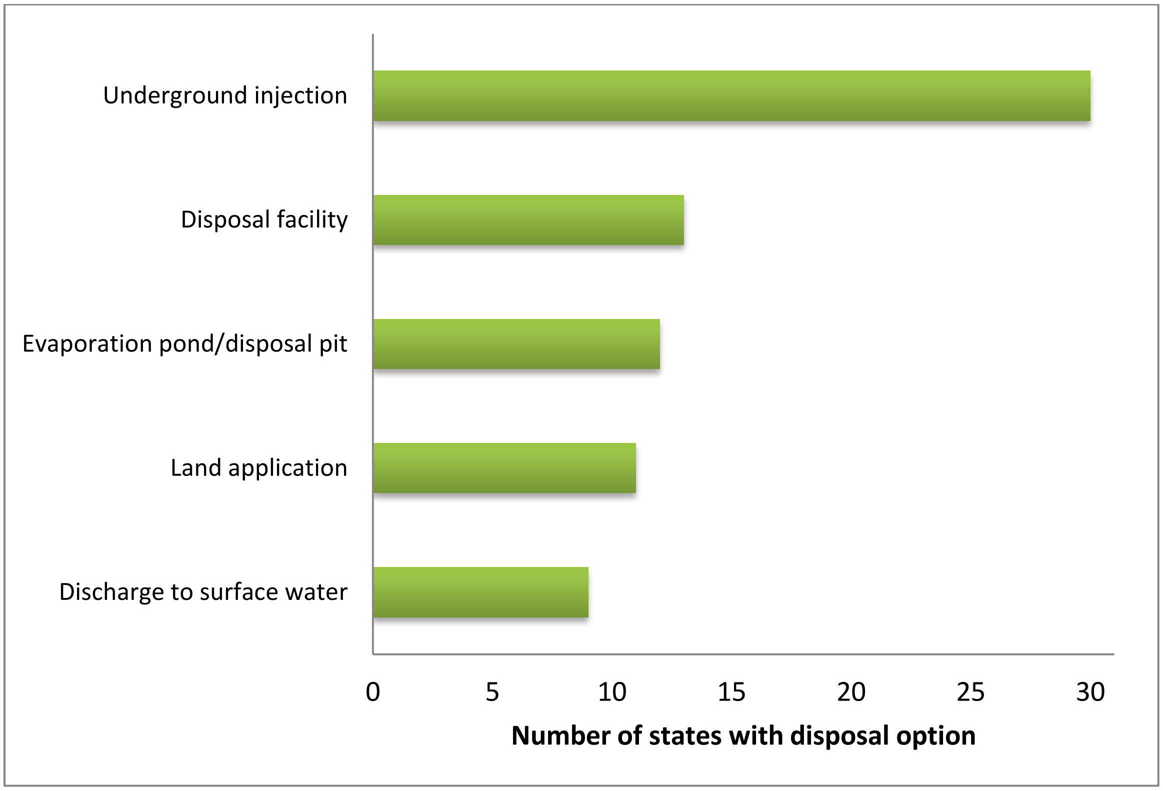


5.4.5 Other Disposal Options

Figure 10 shows the most common fluid disposal options available under state regulations. Recycling of wastewater for future fracking is often not explicitly discussed in state regulations, but we assume it is permitted in all states, and this option is therefore not shown. Some states do mention or encourage recycling in their regulations, as detailed below. Otherwise, underground injection is the disposal option most often explicitly mentioned and allowed by state regulations (30 of 31 states). Disposal of wastewater at treatment facilities is the second most common form of wastewater disposal allowed (13 states).[99]

[99] Pennsylvania law allows disposal of wastewater via treatment facilities. In 2011, however, the state Department of Environmental Protection entered into voluntary agreements with the drilling firms in the state to cease delivering wastes to these facilities. See letter from Shawn M. Garvin, US Environmental Protection Agency (EPA) Regional Administrator, to Michael Krancer, Secretary of the Pennsylvania Department of Environmental Protection, dated May 12, 2011, accessed May 10, 2013, http://www.epa.gov/region03/marcellus_shale/pdf/letter/krancer-letter5-12-11.pdf.

Figure 10. Flowback/Wastewater Disposal Options



Note, however, that although a treatment facility is a "disposal option" from the point of view of a gas operator (and therefore from the point of view of regulations governing those operators), the eventual fate of waste products depends on the practices of and regulations aimed at those treatment facilities. After treatment, fluids may be discharged into surface water, buried, applied to land or roads, or otherwise disposed of. Determining the possible fate of all such posttreatment wastes would require a review of treatment facility practices and regulations beyond the scope of this study.

The details of waste disposal regulations vary greatly across states. For example:

- In 11 states, regulations explicitly allow wastewater to be used for "land treatments" such as ice and dust control or road stabilization, though some of these states require advance approval and/or apply restrictive conditions to the practice.
- Rules in 12 states (e.g., New Mexico, South Dakota, Kentucky, Indiana, and Utah) explicitly allow wastewater disposal in pits (terms vary among states but include evaporation pits, percolation pits, permanent pits, surface ponds, or impoundments).
- Indiana allows evaporation pits only for "backwash water."[100]
- Regulations in nine states (e.g., Illinois, Kentucky, Louisiana, Nebraska, Texas, and South Dakota) explicitly allow wastewater to be discharged to surface waters under certain conditions, usually upon approval of an application, with a permit, or on a case-by-case basis.

[100] 312 Ind. Admin. Code 16-5-13(C)

- Texas limits the disposal of liquid waste materials into estuarine zones to saltwater and other materials that have been previously treated.
- Indiana allows "oil or fluid contaminated with oil" to be disposed of in a solid waste land disposal facility if such disposal is approved by the Department of Environmental Management[101].
- Kentucky allows wastewater to be disposed of through "reverse osmosis."[102]
- Louisiana permits "passive pit closure."[103]

A few states have specific regulations for wastewater reuse, though it is not mandatory in any surveyed state. Utah suggests that "recycling should be used whenever possible and practical."[104]

API best practice is that "operators should consider options for the recycling of fracture treatment flow back fluid"[105] and that disposal options include landspreading, roadspreading, on-site burial, on-site pits, annular injection, underground injection wells, regulated and permitted discharge of fluid, incineration, and off-site commercial facilities.

Drill fluids, muds, and cuttings are also produced or discarded as a result of the drilling process. These are usually produced in smaller volumes than flowback or produced water; partly for this reason, these materials are considered to be a lesser environmental risk. In contrast to wastewater, these may—in some cases, and in some states—be buried on-site or put back down the wellbore.

- Arkansas allows only water-based drill fluids to be placed back down the wellbore or solidified and buried on-site.
- Nebraska similarly specifies that landfarming (also called landspreading) of freshwater-based drilling muds may be allowed.
- Texas has the most specific restrictions, allowing only water-based drilling fluids and cuttings with less than 3,000 milligrams per liter of chlorides to be landfarmed (if greater, they can be disposed of by burial).
- Pennsylvania, however, allows all drill cuttings to be disposed of through land application.
- Virginia allows drill cuttings and solids to be disposed of in on-site pits.
- Colorado specifies that drilling fluids may be dried and buried in pits on non-cropland only.
- Maryland allows cuttings to be landfarmed with department approval.
- Michigan mandates that solid salt cuttings be taken to a designated facility or dissolved and the resulting brine disposed of properly.
- Oklahoma provides the most options for drill fluids and cuttings: evaporation/dewatering and backfilling, chemical solidification, annular injection (with permit), land application (with permit), permitted commercial pit, permitted recycling/reuse facility.

[101] 312 Ind. Admin. Code 16-5-27
[102] 401 Ky. Admin. Regs. 5:090.9(5)
[103] La. Admin. Code tit. 43, § XIX.313.G
[104] Utah Admin. Code r. 649-9-2.2.1
[105] API Guidance Document HF2, "Water Management Associated with Hydraulic Fracturing," First Edition, June 2010: Section 7.6.

5.4.5.1 Dynamism

Several states have recently updated fluid and other waste disposal options and requirements. Ohio previously allowed roadspreading of brine but added a provision to its code clarifying that "[o]nly brine that is produced from a well shall be allowed to be spread on a road" and that roadspreading is prohibited for "fluids from the drilling of a well, flowback from the stimulation of a well, and other fluids used to treat a well."[106] Pennsylvania also asked operators to stop sending oil and gas wastewater through 15 wastewater treatment plants in the state.[107]

5.4.6 Wastewater Transportation Tracking

Wastewater that is not reused, recycled, or disposed of on-site must be transported elsewhere for disposal, sometimes in pipelines but usually by truck.

5.4.6.1 Regulation

Seventeen states regulate this wastewater transportation and/or require it to be tracked and recorded (see Map 16). Of these 17 states, 11 require both a permit for wastewater transport and recordkeeping by transport firms. Two require permits but not recordkeeping, and four require recordkeeping but not permits. Fourteen states (four of them without significant development) require neither. Among the states that require recordkeeping, 10 also stipulate the number of years that such records must be kept available to inspectors, ranging from 2 to 5 years with an average of 3.7 years.

Generally, recordkeeping requirements include the names of the operator and transporter, the date the wastewater was picked up, the location at which it was picked up, the location of the disposal facility or destination of the shipment, the type of fluid being transported, the volume, and how it is being disposed of. State requirements differ, however.

- Alabama requires waste transporters to have a "certificate of eligibility."[108]
- Arkansas, Illinois, and Michigan have additional requirements for transportation system operations, including a requirement that transportation vessels be monitored for leaks.
- Illinois has separate permit requirements for operating a waste transportation system and for the waste transportation vehicle itself.
- Louisiana and Oklahoma require monthly reports of waste receipts.
- Ohio requires annual reports of such waste receipts.
- Either well operators or wastewater transporting firms may be responsible for ensuring that all information is tracked and reported.

API best practice is that wastewater should be transported "in enclosed tanks aboard [US Department of Transportation] compliant tanker trucks or a dedicated pipeline system,"[109] but API does not specifically recommend recordkeeping practices.

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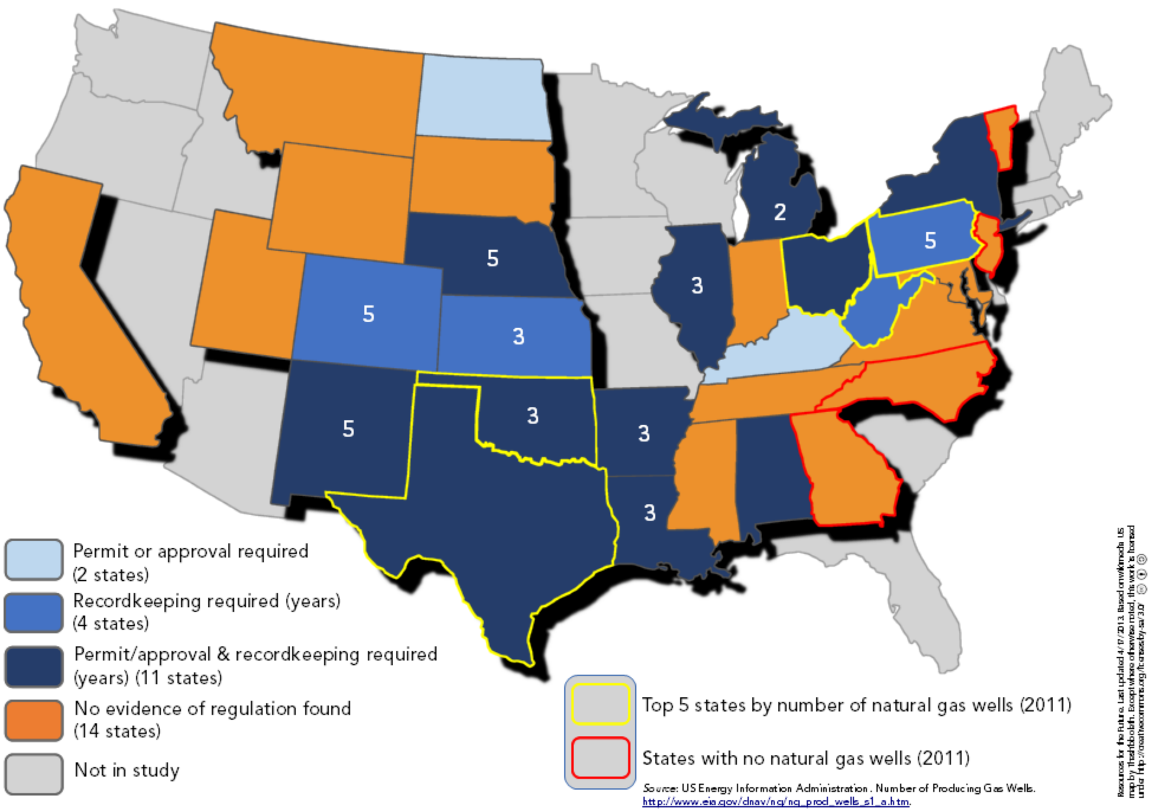
[106] Ohio Rev. Code § 1509.226 (B)(10), text described added by Substitute S.B. 165 (signed by Governor Strickland 2010).
[107] Press Release, Commonwealth of Pennsylvania Dept. of Envtl. Protection, DEP Calls on Natural Gas Drillers to Stop Giving Treatment Facilities Wastewater (Apr. 19, 2011), http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=%2017071%20&typeid=1.
[108] Ala. Admin. Code r. § 400-1-9.03

Map 16. Wastewater Transportation Tracking Regulations



5.4.6.1 Dynamism

As introduced above, states in the past have required tracking of wastes, and some have recently added or updated tracking requirements. West Virginia added a requirement that if "drilling, fracturing, or stimulation" of a horizontal well requires more than 210,000 gallons of water during "any thirty day period," the operator shall prepare a water management plan that describes "[t]he planned management and disposition of wastewater after completion from fracturing, refracturing, stimulation, and production activities."[110] Under another new provision in West Virginia, operators must report the actual "delivery or disposal locations of water" and "[t]he method of management or disposal of the flowback and produced water."[111]

5.4.6.2 Heterogeneity

Few obvious geographical patterns exist in the distribution of wastewater transportation tracking regulations. All of the top natural gas-producing states, except for Wyoming, require both permit and recordkeeping, and none of the four states without significant production require either.

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[109] API Guidance Document HF3, "Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing," First Edition, January 2011: Section 10.1.

[110] W. Va. Code § 22-6A-7(e), added by H.B. 401 (signed by Gov. Tomblin December 22, 2011).

[111] W. Va. Code § 22-6A-8(g), added by H.B. 401 (signed by Gov. Tomblin December 22, 2011).

5.5 Excess Gas Disposal

Before and during production, excess gas may be vented or flared if it cannot be stored or used commercially. These practices have environmental consequences, however. They may result in emissions of volatile organic compounds (VOCs) or other pollutants regulated due to their effects on human health. Both venting and flaring also result in GHG emissions—venting of natural gas releases methane, a potent GHG, whereas flaring emits carbon dioxide. Because of these risks and effects, venting and flaring practices are frequently regulated by states.

5.5.1 Venting

Venting is the release of gas from the wellbore into the atmosphere. It is usually associated with either gas produced incidental to oil drilling, which may occur in areas without natural gas pipeline infrastructure, or with gas produced during the initial drilling and fracking process.

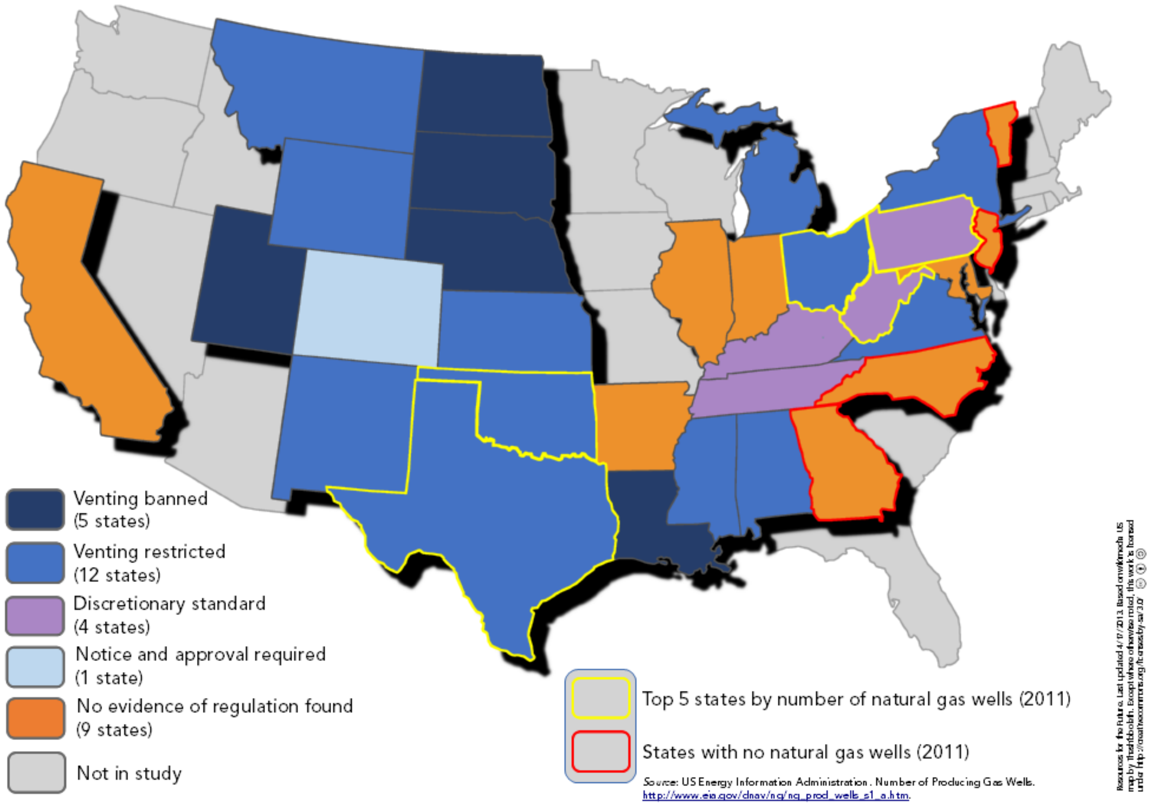
5.5.1.1 Regulation

Five states (Utah, North Dakota, South Dakota, Nebraska, and Louisiana) ban venting (see Map 17). In these states, gas must be flared or sold. Seventeen states allow venting but restrict the practice in some fashion. One state (Colorado) requires advance notice and approval for any venting. Four (Kentucky, West Virginia, Pennsylvania, and Tennessee) have what can best be characterized as discretionary or aspirational standards. These require operators to minimize gas waste or avoid harm to public health but probably do not create any enforceable requirement. The remaining nine states (four of which do not yet have significant gas development) do not restrict venting.

The remaining 12 states' venting regulations are highly variable. Some states have specific restrictions, such as the number of days on which venting may occur, the amount of gas that may be vented, or the development phases during which gas may be vented. Venting may be allowed during well cleanup, testing, or emergencies, but otherwise banned; the following examples illustrate this variation.

- Louisiana prohibits venting unless it can be shown that the prohibition causes economic hardship—we classify this as a ban.
- Michigan allows venting under approved conditions at a gas well that produces less than 5,000 cubic feet per day—we classify this as allowing venting with specific restrictions.

Map 17. Venting Regulations



5.5.1.2 Dynamism

Several states have recently modified venting requirements, with Colorado providing one of the most dramatic examples of change. In 2008, Colorado added a regulation providing the following: "Green completion practices are required on oil and gas wells where reservoir pressure, formation productivity, and wellbore conditions are likely to enable the well to be capable of [sending] naturally flowing hydrocarbon gas in flammable or greater concentrations at a stabilized rate of five hundred (500) MCFD [thousand cubic feet per day] to the surface" against a particular backpressure.[112] Green completion requires "sand traps, surge vessels, separators, and tanks" that "maximize resource recovery and minimize releases to the environment."[113]

5.5.1.3 Heterogeneity

Venting is banned in the upper plains states (North Dakota, South Dakota, and Nebraska). This may be due to large-scale shale oil operations in this area, especially North Dakota, with associated gas production that would otherwise be vented. Otherwise, no obvious patterns emerge. However, these same states do not restrict gas flaring.

[112] 2 Colo. Code Regs.§ 404-1:805(b)(3), text described added by COGCC, final rule amendments (December 17, 2008).
[113] id.

5.5.2 Flaring

Flaring is the process by which excess gas is burned off in stacks or flares. When burned, methane is converted to carbon dioxide, a less potent GHG.

5.5.2.1 Regulation

Unlike venting, flaring is not prohibited in any state. However, most states (20) do regulate the practice in some way (see Map 18). Of the remaining 11 states for which we found no evidence of flaring-related regulation, four have little or no shale gas development, and three are among the states that ban venting, and which can therefore be considered to have significant regulatory control over disposal of excess gas, if not specifically over flaring practices.

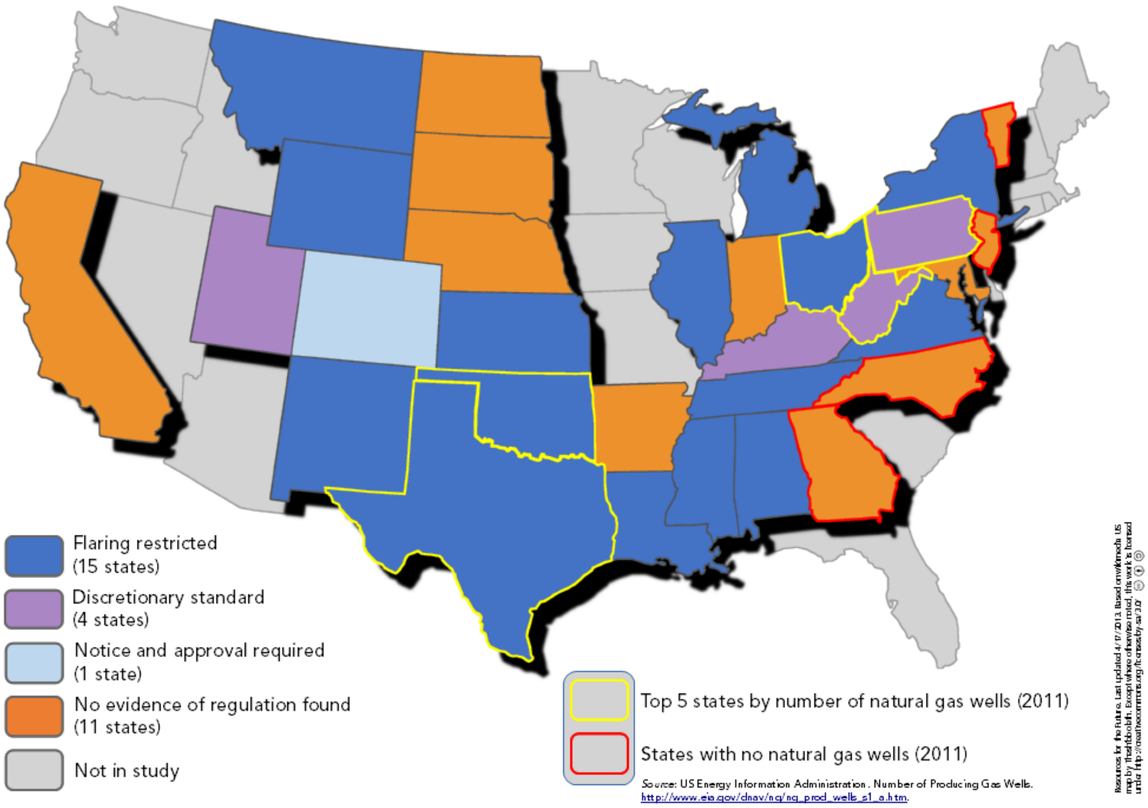
Among the 20 states that do regulate flaring practices, the following illustrate the range of rules.

- Only Colorado requires explicit notice and advance approval.
- The remaining 19 states' regulations are variable. Some (15) restrict the amount of gas that may be flared, the location of flares, or the development phases during which gas may be flared.
- Montana, for instance, requires operators of wells releasing any gas containing at least 20 parts per million of hydrogen sulfide to burn all such gas.
- Louisiana allows gas to be flared provided that no open flame is located closer than 200 feet from any building not used in operations on the drill site and the open flame is screened in such a way as to minimize detrimental effects to adjacent property owners.
- Michigan similarly mandates that flares must be at least 100 feet from a well or tank and 300 feet from structures used for public or private occupancy or from any other flammable or combustible material.

Pennsylvania, Utah, West Virginia, and Kentucky have aspirational or discretionary standards similar to those discussed above for venting practices. These require operators to minimize gas waste or avoid harm to public health but do not create any enforceable requirement.

API suggests that all gas resources of value that cannot be captured and sold should be flared and recommends that flares be restricted to a safe location and oriented downwind considering the prevailing wind direction at the site. This recommendation exceeds the stringency of the nine states that do not restrict venting. Moreover, it exceeds the stringency of the 17 states that allow venting but restrict or regulate it.

Map 18. Flaring Regulations



5.5.2.1 Dynamism

It appears that few states have substantially changed their flaring regulations. Texas' Eagle Ford Task Force reviewed flaring, noting that "[t]he number of flaring permits issued … has paralleled the booming growth of exploration."[114] The Task Force concluded, however, that "[f]lares are emission control devices" and that despite the growth of flaring, total flaring is small in comparison to the state's "more than 151,000 active oil wells."[115] After reviewing comments regarding flaring at a Task Force meeting, Railroad Commissioner David Porter introduced a flaring initiative that would "[a]mend Commission flaring rules to correspond with the increased production of the shale plays around the state," among other initiatives, and encourage the use of "excess gas as a strategic source of power generation."[116] Colorado has also added a provision that flared gas "shall be directed to a controlled flare … as efficiently as possible to provide maximum reduction of air contaminants where practicable."[117]

[114] Railroad Commission of Texas, "Eagle Ford Shale Task Force Report," March 2013:80.
[115] id.
[116] Railroad Commission of Texas, *Eagle Ford Shale Task Force Report* (Austin, TX: Railroad Commission of Texas, March 2013), 76–84, accessed May 10, 2013, http://www.rrc.state.tx.us/commissioners/porter/reports/Eagle_Ford_Task_Force_Report-0313.pdf.
[117] 2. Colo. Code Regs. § 404-1:912(d), text described added by COGCC, final rule amendments (December 17, 2008).

5.6 Production

As noted above, shale gas production is the subject of less state oversight than the drilling and development processes. This is not surprising as producing wells are relatively static and low-maintenance compared to the intensive activity of the drilling and fracking processes. To the extent that environmental risks from producing wells exist, they are likely to be a result of improper drilling or fracking practices (or accidents). There are exceptions, of course. Active wells may generate produced water, which must be disposed of properly. Produced water practices are generally regulated under the same provisions as those discussed above for wastewater generated during initial development. Wells may be refracked to increase production, and operators must follow the same state rules as for initial frack jobs. Accidents must be reported as required by state law regardless of whether a well is producing. Our analysis does not, however, include any state environmental regulations that uniquely apply to producing wells.

5.6.1 Taxes

Perhaps the most significant state law relevant to producing wells is not an environmental regulation at all, but the state's severance tax. Severance taxes are taxes imposed on gas production. Though not strictly speaking "regulations," these taxes are an important part of the relationship between state governments and the oil and gas industry. However, they are not the only state tax burdens facing operators. Other state taxes, whether general taxes or those specific to the oil and gas industry, also apply to operators. Only taxes specifically based on the volume of extracted gas are detailed in this section.

5.6.1.1 Tax Rates and Calculation

Of the 31 states in our survey, 26 have severance taxes (see Map 19). Pennsylvania and New York are the only states with significant shale gas production that lack such taxes, and each is a special case. Pennsylvania recently enacted an "impact fee" that is assessed on operators in counties that choose to impose the fee.[118] Fees are charged on a per-well basis, regardless of production, and are therefore not severance taxes as such.[119] New York, as noted above, is currently considering whether to lift its shale gas development moratorium. If and when that moratorium is lifted, New York could impose a severance tax (or an impact fee), though conventional gas operations in the state do not currently pay either.

States with severance taxes vary not only in rates, but also in how they are calculated. States generally use one of two methods to calculate the tax—either a percentage of the market value of the gas extracted (18 states) or a fixed dollar amount per quantity extracted (5 states). Three states use a hybrid approach in which the percentage tax varies between different levels based on the gas price.

Some state severance taxes vary based on production levels, length of production period, well characteristics, or other factors.

- In Montana, the tax rate is 0.5 percent for the first 18 months of a well's operation (compared to 9 percent thereafter).

[118] 58 Pa.C.S. §§3201-3274.

[119] *Id*. Impact fee payments do vary based on the prevailing price of gas and decline over the life of the well. But they are not specifically tied to production at a given well.

- In Utah, the tax rate is 3 percent of the first $1.50 in sold gas value per thousand cubic feet (Mcf) and 5 percent of the remainder.
- Indiana assesses a tax of 3¢/Mcf or 1 percent, whichever is greater; in other words, it charges a fixed rate when gas is sold below $3/Mcf, and a percentage rate when it is sold for higher prices.
- Oklahoma reduces its tax rate if gas prices drop below $2.10/Mcf.
- In Colorado, the tax rate differs depending on the gross value of gas extracted by the operator, varying from 2 percent (under $25,000) to 5 percent (over $300,000).

Some states (such as Maryland and Virginia) leave severance taxes to local governments, though Maryland is debating a 2.5 percent statewide severance tax that would be imposed on top of any local taxes[120] (currently Allegany County's 7 percent and Garrett County's 5.5 percent tax). Virginia limits local severance taxes to 1 percent.

Several states offer incentive programs that can reduce severance tax burdens.

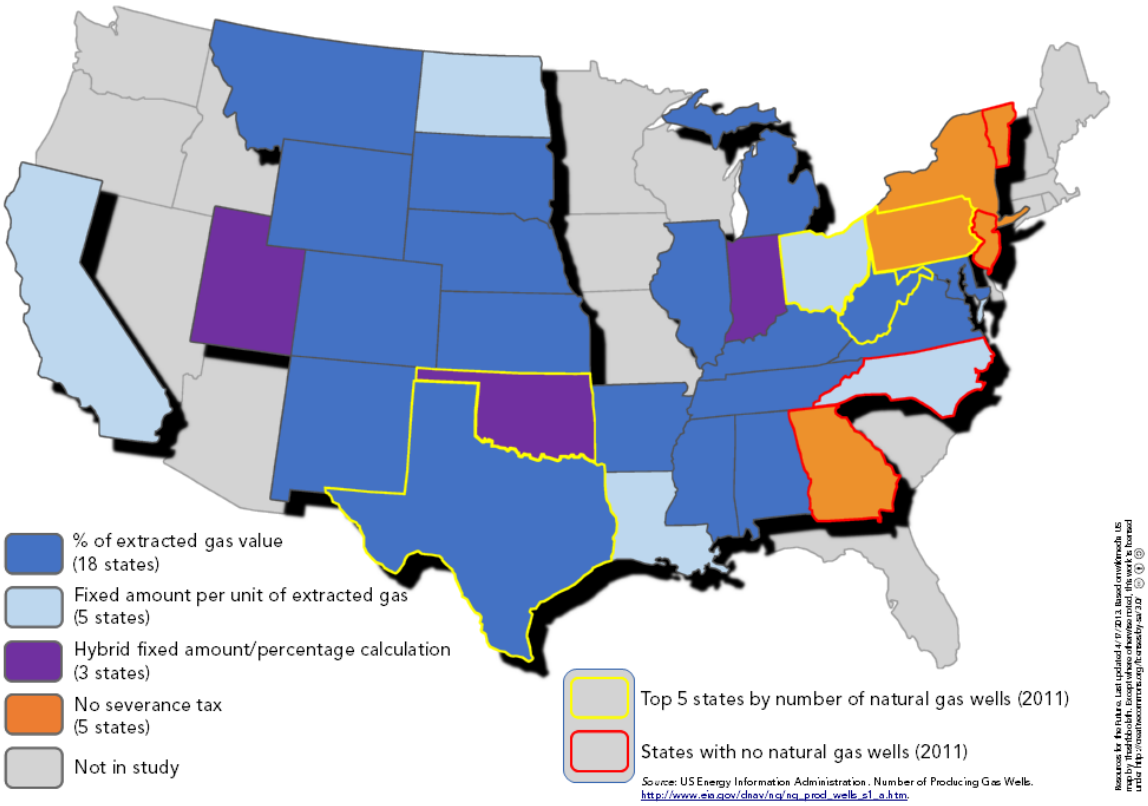
- Louisiana, for instance, offers discounts for "incapable" wells.[121]
- Montana offers a decreased rate for "non-working interests."[122]
- Oklahoma lowers the tax according to the price of gas at market.
- Texas can lower taxes for high-cost wells and inactive wells.

As gas prices change, severance tax rates vary in either percentage or dollar terms (depending on which of the two methods the state uses to calculate its tax). For the maps below, we show taxes given a prevailing gas price of $2.46 and $5.40 per Mcf in both percentage and dollar terms. The former figure was the Henry Hub price in 2012 during our initial review (it has since increased somewhat), and the latter is EIA's long-term (2030) forecast price.[123] To compare rates, one must convert percentage-based taxes into fixed dollar amounts (or vice versa). At $2.46/Mcf, for example, a state with a 1 percent severance tax would have the same tax rate as a state with a 2.46¢/Mcf dollar value tax rate. But at a different price, effective state tax rates would change—at a higher gas price, states with percentage-based taxes would charge a higher tax per Mcf, and states with fixed dollar value taxes would charge a lower percentage rate (and vice versa for lower gas prices).

To calculate and compare states' severance tax rates, we used each state's prevailing long-term tax rate for producing wells (i.e., ignoring any incentive programs or lower rates during initial production), and the highest rate charged by any county if taxes are set at the county level.

[120] Md. S.B. 879.
[121] La. Rev. Stat. Ann. § 47:633(9)(c)
[122] Mont. Admin. r. 42.25.1809
[123] EIA, *Annual Energy Outlook 2013 Early Release*, 5.

Map 19. Severance Tax Calculation Method



At a $2.46/Mcf gas price, we found that the national average tax rate is about 11¢/Mcf or 4.5 percent (see Map 20). Tax rates vary from 0.02 percent (0.05¢/Mcf) in North Carolina to 9 percent (22.14¢/Mcf) in Montana. In dollar terms, six states—North Carolina, California, Indiana, Illinois, Ohio and Virginia—have the lowest tax rates, at or under 3¢/Mcf. Four of the six states that set their tax rates in dollar value terms are in this group. All states other than these six and Montana have rates clustered between 7¢ and 20¢/Mcf.

Because a $2.46/Mcf gas price is relatively low by historical standards, one would expect the states with fixed-dollar taxes to have relatively high taxes in percentage terms, and those states with percentage taxes to have relatively low taxes in dollar terms, compared to other states. But this is not the case—the average percentage-based tax in fixed-dollar tax states is more than 2 percentage points lower than the national average, and the average per-Mcf tax in percentage tax states is more than 1.5¢/Mcf greater than the national average.

At a $5.40/Mcf gas price, the average is about 23¢/Mcf or 4.2 percent (see Map 21). North Carolina (0.01 percent or 0.05¢/Mcf) and Montana (9 percent or 48.6¢/Mcf) still have the lowest and highest tax rates, respectively. In dollar terms, the same six states have the lowest tax rates, all under 6¢/Mcf. But the higher gas price makes differences among states with percentage-based tax rates more pronounced. Setting aside the six low-tax states and Montana, rates vary between about 9¢ and 43¢/Mcf.

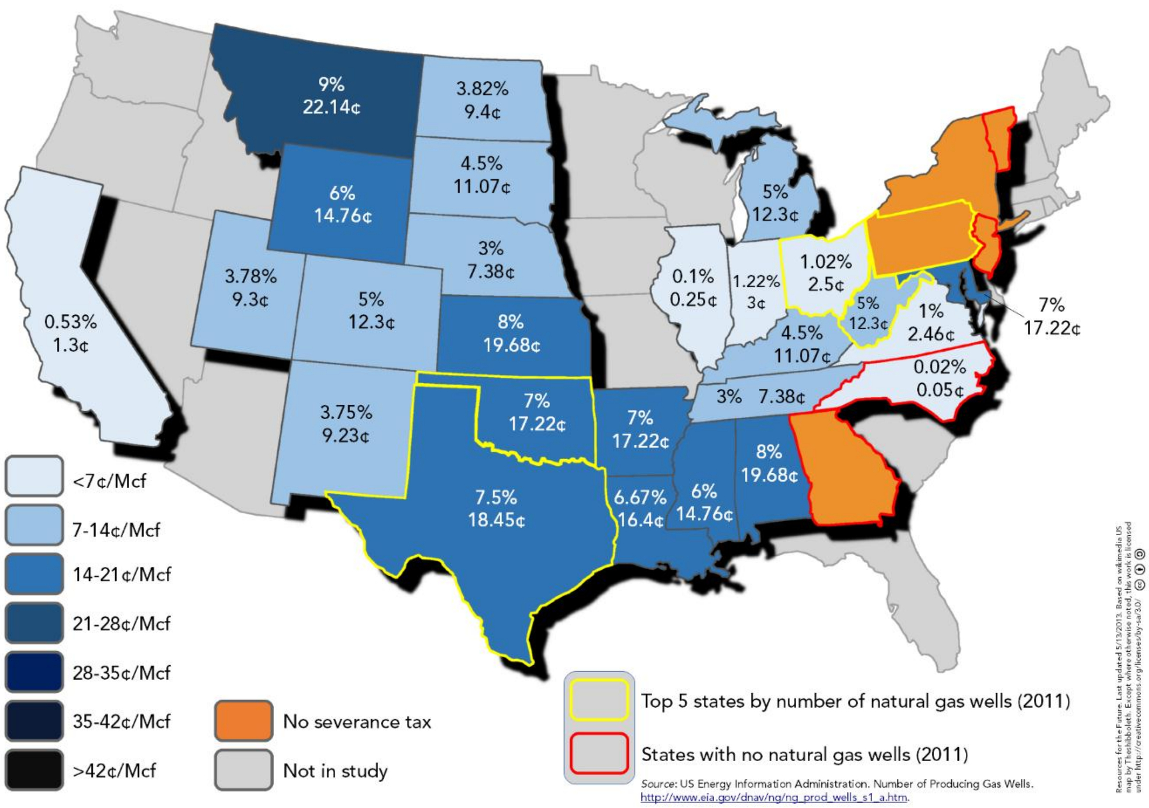
5.6.1.2 Dynamism

Pennsylvania has made one of the most recent taxation changes in the natural gas area, although the constitutionality of its fee provision remains unclear.[124] In 2012, Pennsylvania approved an unconventional well fee, which counties or municipalities may vote to adopt. The fee, if adopted within a county or municipality, "is imposed on every producer" and applies to all spudded unconventional gas wells. The amount of the fee varies depending on the average annual price of natural gas.[125]

5.6.1.3 Heterogeneity

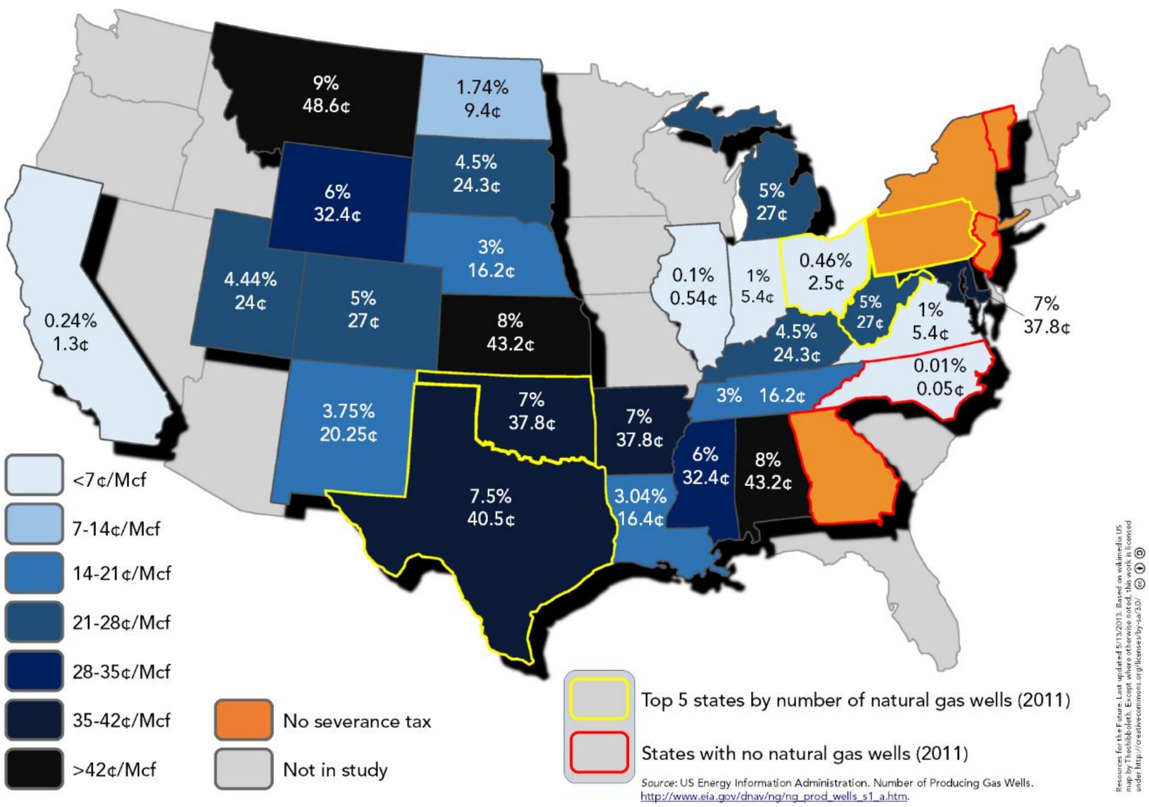
The majority of states calculate severance taxes as a percentage of extracted gas value, rather than as a fixed amount. But we found no obvious geographic pattern. Tax rates are among the most heterogeneous elements in our analysis, though this is perhaps not surprising given the very different fiscal situation and mix of taxes in each state.

Map 20. Severance Taxes at $2.46/Mcf Gas Price



[124] *Robinson Twp. v. Com.*, 52 A.3d 463 (Pa. Cmwlth. 2012), currently under review before the Pennsylvania Supreme Court.
[125] 58 Pa. C.S. § 2302(a)-(b), text described added by H.B. 1950 (approved by Governor Corbett February 14, 2012).

Map 21. Severance Taxes at $5.40/Mcf Gas Price



5.7 Plugging and Abandonment

State regulation becomes somewhat more significant at the end of well life. When a well is no longer producing, it must be permanently plugged and abandoned. Wells may also be taken out of production and, oxymoronically, "temporarily abandoned." Most states have detailed plugging and abandonment procedures to ensure that the well does not become a conduit for contamination through migration of fluids and gases from nearby wells being fractured. Our analysis includes two elements of these regulations: maximum well idle time and maximum temporary abandonment time.

5.7.1 Well Idle Time

An idle well is one that is not currently producing oil or gas. Generally, wells are not permitted to remain idle indefinitely, but instead must be properly plugged to minimize the risk of damage or contamination.

5.7.1.1 Regulation

Of the 31 states in our survey, 28 regulate the duration over which a well is allowed to sit idle (see Map 22). Beyond this time period, operators have a choice: they can restart production at the well, temporarily abandon it (if allowed by the state—see next section), convert it to a waste disposal well (contingent on state rules), or permanently plug and abandon it.

Among states that regulate maximum idle times, the range is from 1 to 300 months, with a mean of 23.5 months[126] (and a mode of 12 months, in 13 states). These figures hide some complexity. First, many states allow well idle times to be extended by regulators if operators apply to do so and meet certain conditions. This is a good example of state regulation that uses a hybrid command-and-control/case-by-case permitting approach. For our analysis, we classed all such states as command and control because this is their primary and initial regulatory tool. Further, we indicate the initial idle time allowed under those command-and-control regulations because it is usually impossible to determine how much additional time regulators may grant to operators who apply for extensions, or how often those extensions are granted.

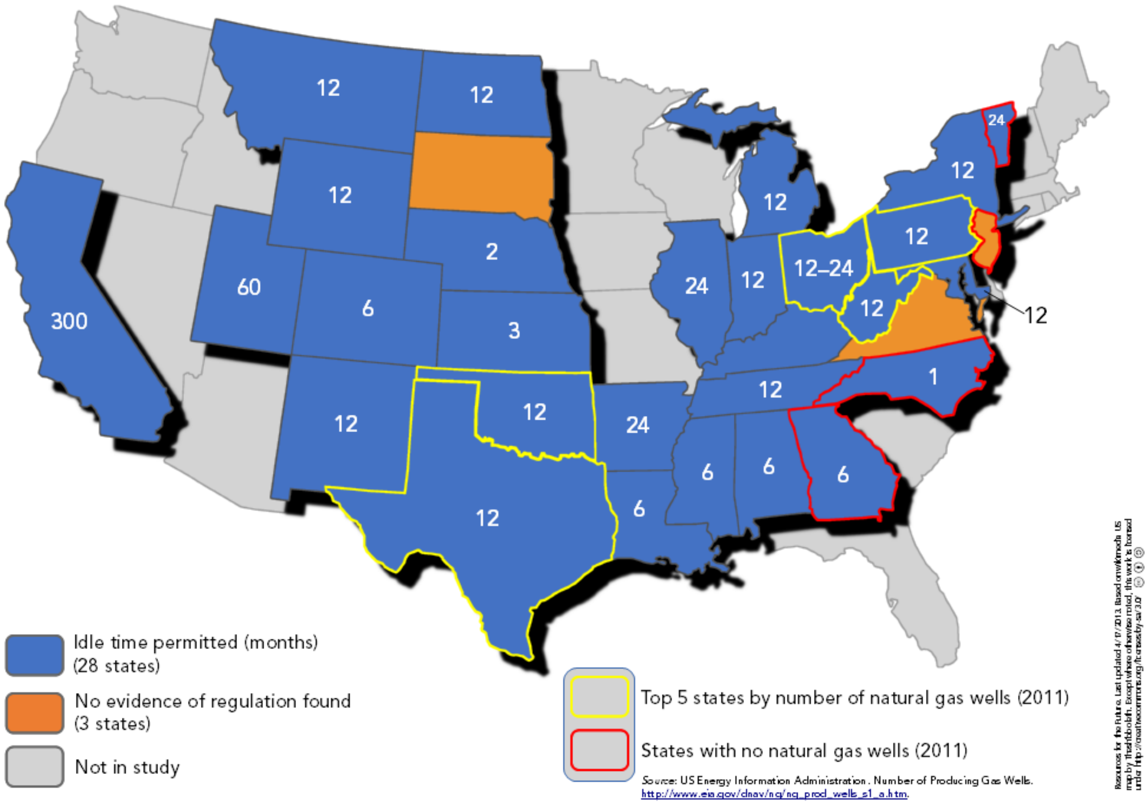
Second, several states have a range of permitted idle times depending on whether the well is a productive well or a non-productive well, or depending on the casing installed in the well. For our analysis, we show the maximum idle time allowed for completed, productive wells.[127]

- Oklahoma, for example, specifies that wells that have only a surface casing must be plugged within 90 days, whereas a well that was completed with production casing may remain inactive for 12 months.
- Texas mandates that plugging operations on an inactive well begin within one year after the drilling or operations cease, but regulators can grant an extension for plugging an inactive well if certain criteria are met.

API does not have a recommended best practice for well idle time.

[126] This average is calculated using the minimum allowed idle time for those states that allow different durations in different circumstances (only Ohio).
[127] Kentucky requires operators to plug wells if they are "no longer used for the purpose for which [they were] drilled or converted" but does not specify how much time operators have to complete this process, or how long a well must be idle before it will be considered to be no longer in use. We therefore treat Kentucky as regulating idle time but do not show a specific time limit.

Map 22. Well Idle Time Regulations



5.7.1.1 Dynamism

In a 2010 rulemaking, Pennsylvania substantially updated its well plugging requirements, although they are unrelated to the timing of closure. It added a provision indicating that the retrievable production casing must be removed "by applying a pulling force at least equal to the casing weight plus 5,000 pounds or 120 percent whichever is greater" and adding other requirements for filling the hole with non-porous material.128

5.7.1.2 Heterogeneity

All but a few states limit well idle time. As noted, nearly half of the states that do so limit it to a year. Otherwise, however, significant heterogeneity exists. California is a significant outlier, allowing wells to remain idle for 25 years. In the other direction, Nebraska, Kansas, and North Carolina allow wells to remain idle for three months or less. States do seem to cluster. Most states in the Northeast allow one year of idle time, and most in the South allow six months. Plains states with significant production also allow a year.

[128] Environmental Quality Board, Proposed Rulemaking, Oil and Gas Wells, July 10, 2010, codified at 25 Pa. Code § 78.92.

5.7.2 Temporary Abandonment

When a well is no longer producing at an economical rate, an operator may choose to stop production but not to immediately and permanently plug the well. Many states allow operators to temporarily abandon wells, allowing them to remain idle but—in most cases—requiring operators to take various measures to reduce the risk of damage to or contamination of the well. For example, Colorado requires temporarily abandoned wells to have the wellbore isolated from the surface with a cement retainer or other barrier.[129] Temporary abandonment is essentially a formalized way of leaving a well idle, with added safety or maintenance requirements; in most cases, it is invoked after a well has been idle for the maximum allowable time.

5.7.2.1 Regulation

Of the states in our study, 22 specifically allow and regulate temporary abandonment (see Map 23). In those states without temporary abandonment regulation, the general well idle time rules (if any) apply: wells must be plugged once well idle time expires. Seven states have well idle time limits but do not provide for a separate temporary abandonment status in their regulations. We found no evidence of either temporary abandonment regulations or general well idle time limits in the remaining pair of states, Virginia and New Jersey, implying that wells drilled in those states can be idle indefinitely (though New Jersey has no significant production and, until recently, a statewide moratorium).

Typically, permits are required before a well can be temporarily abandoned. When a temporary abandonment permit expires, either the well must be permanently plugged and abandoned, the permit extended, or the well brought back into production. State law also generally limits the amount of time wells can be kept in this status. These limits range from 3 to 60 months, with a national mean of about 23 months (and a mode of 12 months, in seven states).

Operators can often apply for extensions, which also have an expiration date and can have renewal limits. Kansas, for example, will renew a temporary abandonment permit for up to 10 years. The limits stated above and on Map 23 are the *initial* duration of the temporary abandonment permit.

Some states, such as Louisiana and Mississippi, determine whether wells have "future utility"—only those that do can be temporarily abandoned beyond a relatively short timeframe. In Louisiana, for instance, wells with future utility can be temporarily abandoned indefinitely, subject to periodic review by regulators, whereas wells with no future utility must be permanently plugged and abandoned within 90 days.

Other details of abandonment regulations differ among states. Most have different regulations for dry holes; they usually have to be plugged sooner than productive wells. Michigan's temporary abandonment permit runs for 12 months, except that under certain conditions it may be extended to 60 months.

API best practice is that, when a well is temporarily abandoned, it "must be maintained in a condition where routine workover operations can restore a wellbore to service,"[130] but API does not recommend any maximum time period for temporary abandonment.

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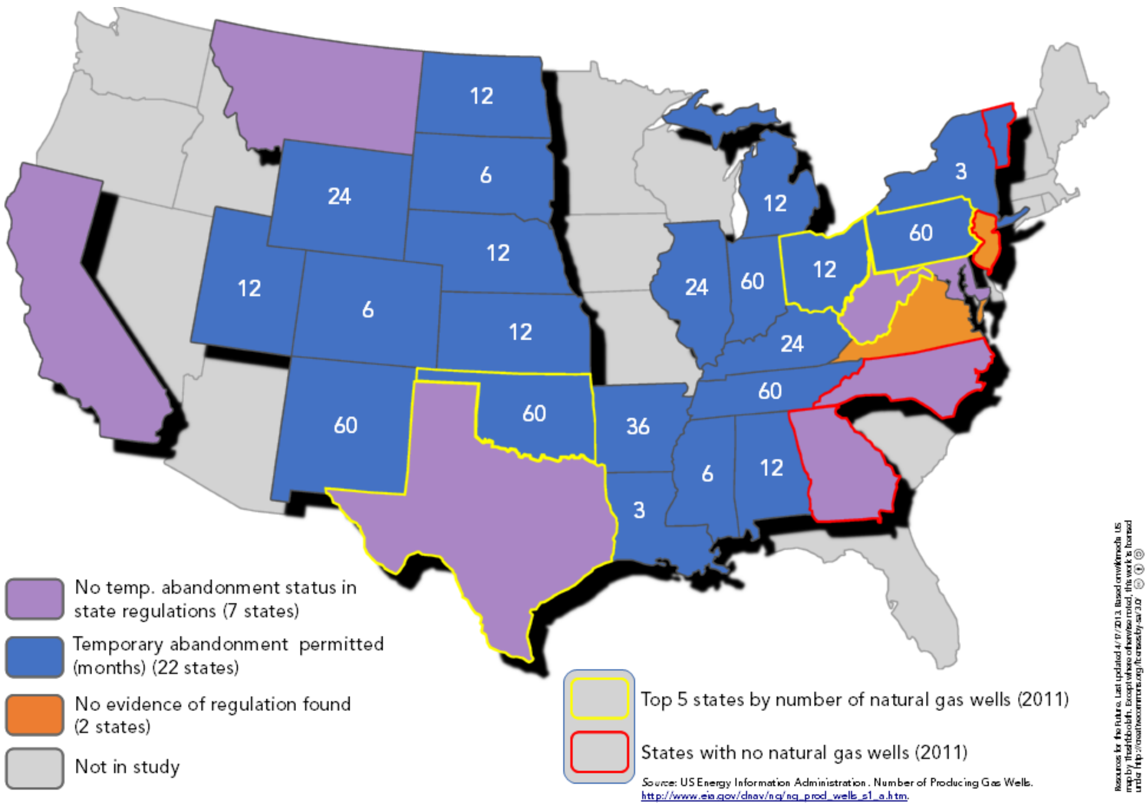
[129] "Glossary of Oil and Gas Terms," COGCC, accessed May 10, 2013, http://cogcc.state.co.us/COGIS_Help/glossary.htm.

[130] API Recommended Practice 51R, "Environmental Protection for Onshore Oil and Gas Production Operations and Leases," First Edition, July 2009: Section 6.4.1.

Map 23. Temporary Abandonment Regulations



5.7.2.2 Heterogeneity

The prevailing rule among states is to allow temporary abandonment status but to limit it. No obvious patterns exist for states' temporary abandonment time limits, though the range is much smaller than that for idle time.

5.8 Other Regulations

5.8.1 Accident Reporting

Generally, accidents at shale gas wells, such as spills, leaks, fires, or blowouts, must be reported to state regulators within a short timeframe. Typically, operators must follow up this initial report by filing a written report detailing the accident within a specified number of days.

5.8.1.1 Regulation

Of the surveyed states, 26 require accident reporting and specify the time within which operators must report (see Map 24).

- Seven states (Montana, Texas, South Dakota, Illinois, Alabama, Mississippi, and Georgia) require immediate reporting.
- Four states (Kentucky, Pennsylvania, Maryland, and New York) require reporting within two hours.

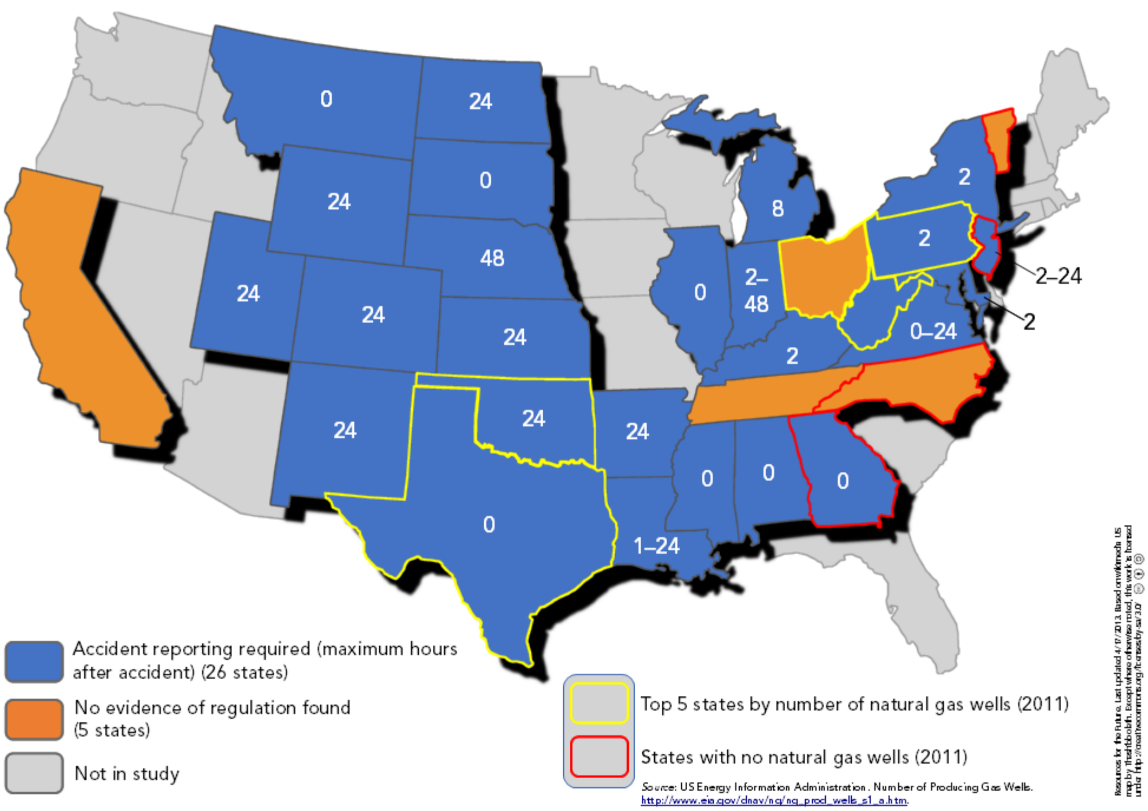
- Two states (Nebraska and Indiana) allow up to 48 hours.
- All other states that require accident reporting allow up to 24 hours.

Several states allow different reporting deadlines depending on the severity of the accident.

- Louisiana and Virginia, for example, require reporting within 24 hours for spills, except those that are categorized as "emergencies" or that create "imminent danger," which must be reported immediately (Virginia) or within 1 hour (Louisiana).[131]
- New Jersey has a 2-hour reporting requirement if potable water supplies are affected and a 24-hour requirement if a USDW is impacted.

API best practice is that "a spill or leak should be promptly reported,"[132] but "promptly" is not defined in terms of any specific timeframe. It is possible that firms would interpret "promptly" as immediate reporting, but not necessarily. This makes it impossible to compare API's recommendation to state reporting time rules.

Map 24. Accident Reporting Requirements



[131] La. Admin. Code tit. 33, § I.3915.A.1; 4 Va. Admin. Code § 25-150-380.A

[132] API Guidance Document HF3, "Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing," First Edition, January 2011: Section 11.2.

5.8.1.2 Heterogeneity

States in the Northeast have relatively short reporting times—two hours in most cases. This is perhaps unsurprising given their population density and, therefore, risks to public health from any accidents. Very few states lack accident reporting requirements.

5.8.2 State and Local Bans and Moratoria

A few states have instituted statewide moratoria on shale gas development while they consider regulatory changes. New York is the most well-known example, but New Jersey and Maryland both have imposed recent moratoria.

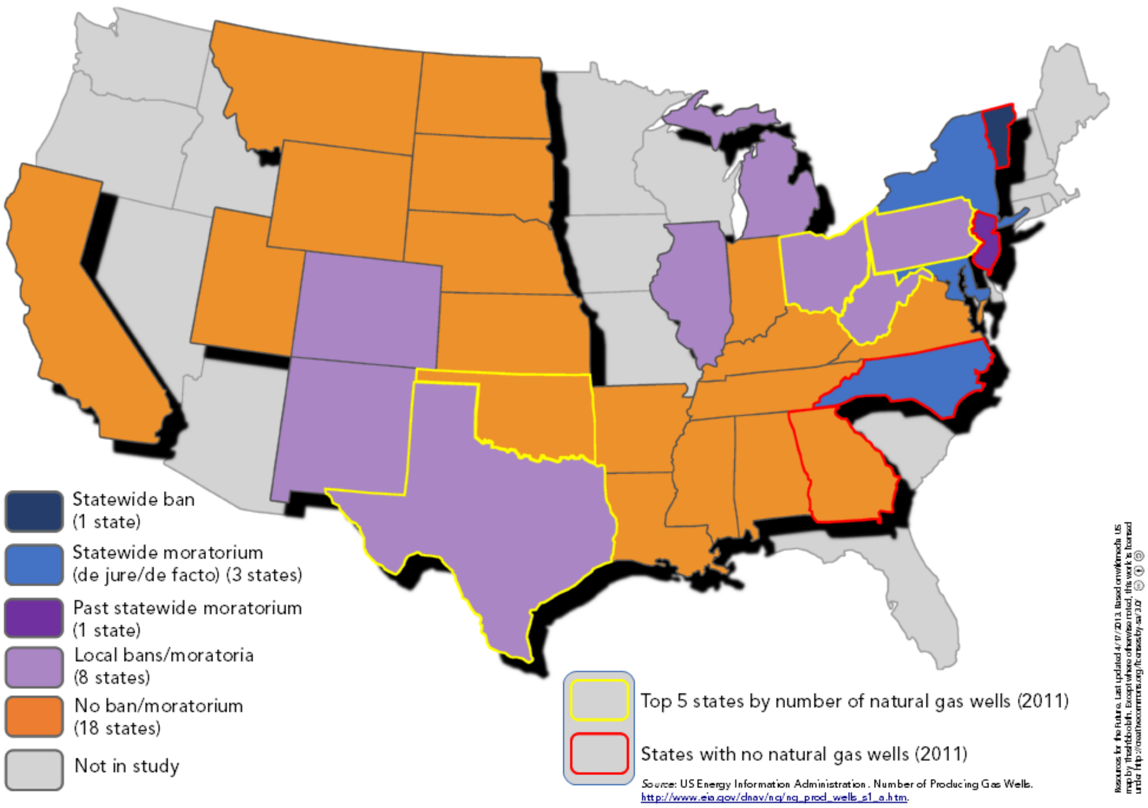
- New Jersey's moratorium expired in December 2012.
- Maryland's is set to expire in June 2014.
- Vermont has also banned development indefinitely, though it is not clear whether the state has any meaningful gas resources.
- North Carolina's de facto ban results from a longstanding ban on horizontal drilling. In 2012, North Carolina passed legislation allowing horizontal drilling in principle, but drilling will not be allowed until a regulatory framework is in place. Such a framework is now being developed.[133]

Local governments in at least eight states have also instituted shale gas development bans or moratoria in their jurisdictions (see Map 25). This practice is controversial in many states. In principle, state law supersedes local law, though local bans/moratoria have been the subject of significant litigation.

- Two New York courts and at least one in Pennsylvania have upheld local development-banning ordinances.[134]
- A West Virginia court ruled a similar local ordinance unconstitutional and unenforceable.[135]
- Longmont, Colorado, recently became the first city in the state to pass a ban on hydraulic fracturing and is now being sued by the Colorado Oil & Gas Association.[136] The outcome of this decision could have far-reaching consequences for the industry in Colorado.

[133] See North Carolina Session Law 2012-143 (Clean Energy and Economic Security Act) (directing the Mining and Energy Commission to "establish a modern regulatory program for the management of oil and gas exploration and development in the State and the use of horizontal drilling and hydraulic fracturing treatments for that purpose").
[134] Pennsylvania Environmental Council, "PEC Statement on the Commonwealth Court's Decision Concerning Act 13," July 27, 2012; "2nd NY Court Upholds Town Ban on Gas Drilling," *The Wall Street Journal*, February 24, 2012.
[135] "Judge Overturns Morgantown Marcellus Shale Gas Drilling Ban," *Charleston Gazette*, August 14, 2011.
[136] Jack Healy, "With Ban on Drilling Practice, Town Lands in Thick of Dispute," *New York Times*, November 25, 2012.

Map 25. Fracking Bans and Moratoria



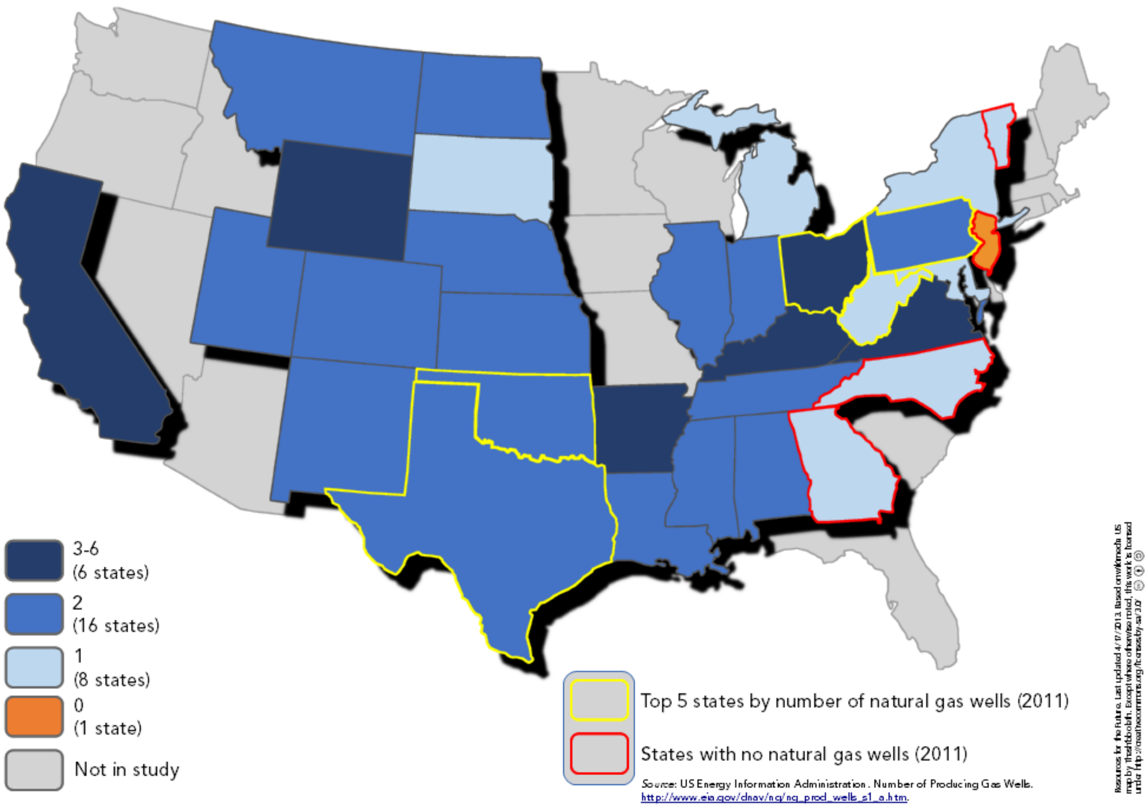
5.8.3 Regulatory Agencies

As the preceding sections show (though they only scratch the surface), regulation of shale gas development is complex. This regulatory complexity is magnified in many states by the fact that multiple regulatory agencies have overlapping jurisdictions. This is over and beyond the overlapping jurisdiction already implicit in a federalized system, in which the federal government, interstate RBCs, and in some cases local governments share authority with states.

Just over half the states in our analysis (16) have two regulatory bodies with authority over shale gas development—usually a natural resources or environmental agency, and an oil and gas regulator (see Map 26). Eight states have only one regulatory body, and six have more than two—up to a maximum of six with some role in regulating development.

- In Texas, the state Railroad Commission has significant regulatory authority.
- New Jersey currently has a one-year moratorium on hydraulic fracturing and has not yet designated an agency to be responsible for regulating shale gas extraction in the event that the moratorium is lifted.

Map 26. Number of State Regulating Agencies



Division of authority does not necessarily imply that a state's regulation is stricter or that it is more (or less) effective, though it does have implications for the level of regulatory complexity.

6. Understanding Heterogeneity

The heterogeneity prevalent across almost all of the regulatory elements discussed in the previous section may or may not be surprising, but it is at least interesting, and begs for explanation. As noted above, regulatory differences among states might reflect underlying differences of state geology, climate, demographics and settlement patterns, levels of experience with oil and gas activity, or environmental vulnerability. Economic, fiscal, or political differences could be important factors. Or regulatory differences could just be the result of more or less random variation built up over decades of developing oil and gas regulations.

Supporters of state-level regulation of shale gas development—primarily but not exclusively industry and state governments themselves—argue that the opportunity to regulate activities and risks differently in different states is an important advantage of regulating at the state level. API, for example, argues that "[s]tate regulation of oil and gas activities . . . is particularly important because it allows laws to be tailored to local geology and hydrology."[137] Either explicitly or by implication,

[137] American Petroleum Institute, *Shale Energy, 10 Points Everyone Should Know* (Washington, DC: American Petroleum Institute, March 2012), 2, accessed May 10, 2013. http://www.api.org/~/media/Files/Policy/Hydraulic_Fracturing/Hydraulic-Fracturing-10-points.pdf

advocates of state-led regulation further argue that current regulatory differences are indeed a reflection of important underlying differences among states, particularly physical (geological or hydrological) differences. Critics of state regulation, on the other hand, argue that states have been captured by industry or that they value jobs and other economic benefits too highly compared to environmental protections.

With our data on state shale gas regulations, it is possible to test various hypotheses regarding heterogeneity, albeit in a limited way. To do so, we developed hypotheses on whether and how various state characteristics are associated (or correlated—we use those terms synonymously) with the regulatory heterogeneity we observed, and tested those hypotheses in regression analyses.

6.1 Limitations

Before discussing this analysis, we note some important caveats. First, correlation is not causation. Just because regulatory heterogeneity is associated with some variable does not mean that states regulatory decisions are influenced by that variable. The variation in both could be caused by an unobserved variable, and in some cases reverse causation is possible. If, for example, more sparsely-populated states have fewer or less stringent shale gas regulations, this may be because such states view development risks as less important because they threaten fewer people—this is direct causation. But it is also possible that people are less likely to settle in some areas because oil and gas development makes them less attractive—an example of reverse causation. Or both relationships could exist—in such cases (and many others), determining causation requires a deeper analysis than we are attempting here. We therefore make no claim here to identify the causes of heterogeneity—at most, we identify associations that are *possible* explanations for heterogeneity.

Just as correlation is not causation but is evidence of it, *lack of correlation* is evidence against causation. Where we failed to identify an association between regulatory heterogeneity and some underlying variable, it is reasonable to be skeptical that the variable can explain the heterogeneity we observed in our sample.

Second, our sample is of course not comprehensive—as noted above, many important regulations relevant to shale gas development are not included in our analysis. This means that further caution is warranted—it is possible that statistically significant findings would not be significant, or that statistically insignificant findings would be significant, if it were possible to test hypotheses across all shale gas regulations.

6.2 Variables and Hypotheses

As discussed in Section 4.2, we identified three types of heterogeneity among state shale gas regulations: variation in the number of elements regulated, in states' choices of regulatory tool, and in the stringency of quantitative regulations. For each of these, we specified a dependent variable: the number of elements regulated by each state, whether a state uses command-and-control or other regulatory tools (performance standards or case-by-case permitting), and the normalized stringency of a state's quantitative regulations.

Note that, as with the general statistics presented in Section 4, this regression analysis excludes the four states in our study without significant shale gas development—Georgia, North Carolina, New Jersey, and Vermont.

We then selected 48 state-level variables that we hypothesized might be associated with the variation we observed across the three dependent variables. These variables fall into several classes. Some are simply regional variables, to test whether states in different parts of the country regulate differently (this is a quantitative look at the qualitative geographic observations made in the previous section). Some are related to the level of oil and gas development, such as the number of gas wells drilled in a given year (2010).[138] Some variables are environmental, such as the percentage of state area that is forested or the number of endangered species designations. Other variables are economic, such as the state gross domestic product (GDP) per capita or the net budget surplus (deficit) normalized by a state's GDP. Others are demographic and may well be a proxy for environmental risk or economic gain, such as the percentage of the state's population living in rural areas. Some are political, such as party voting behavior and self-identified party identification, or have a political component, such as level of donations to environmental groups. And others are geologic and hydrologic, such as the depth to groundwater. We evaluated the relationship between these general variables and the heterogeneity we observed across all states and regulatory elements.

Some of these variables might be associated with different regulatory patterns across some, but not all elements. For example, the presence of a major aquifer or the percentage of freshwater consumption from groundwater in the state are potentially relevant only to those regulations that are aimed at protecting groundwater, such as casing and cementing rules. Therefore, we also evaluated the relationship between some "independent" variables[139] and defined subsets of the regulatory elements in our analysis that apply to specific classes of environmental risks—water quality (also further subdivided into surface water quality/quantity and groundwater quality) and air quality (see Table 3).[140]

Table 3. Elements Classified by Environmental Risk Addressed

Surface water quantity/quality	Groundwater quality
1. Predrilling water well testing requirements	1. Water setback requirements
2. Water setback requirements	2. Predrilling water well testing requirements
3. Water withdrawal limits	3. Casing/cementing depth regulations
4. Freeboard requirements	4. Cement type regulations
5. Pit liner requirements	5. Surface casing cement circulation rules
6. Wastewater transportation tracking rules	6. Intermediate casing cement circulation rules
Air quality	7. Production casing cement circulation rules
1. Venting	8. Pit liner requirements
2. Flaring	9. Underground injection regulations

[138] For this variable, and some others with long "tails," we converted them into logarithms.

[139] We put independent in quotes because some of these variables may not really be independent of the regulatory metrics, such as those that could be involved in reverse causation. In a regression, the variables in tables 4 through 10 are also termed right hand-side variables

[140] To address this subset of variables that may help explain regulatory behavior, we created dummy variables for each type of regulation (e.g., air and water) and interacted them with the applicable "independent" variable in question.

Tables 4 through 10 list the variables we tested in our analysis. Where appropriate, they also show our hypotheses regarding their relationship with regulatory heterogeneity in our sample—that is, whether and how the variable is associated with the number of elements regulated and the stringency of quantitatively regulated elements. Hypothesized associations could be either positive (greater values for the variable associated with more or stricter regulations) or negative (greater values for the variable associated with fewer or less strict regulations). We did not have strong hypotheses about correlations between these variables and states' choice of regulatory tool.

Table 4. Variables and Descriptive Statistics

Group	States included[141]
Northeast (Marcellus)	New York, Pennsylvania, Ohio, West Virginia, Maryland, Virginia
Midwest	Indiana, Illinois, Michigan, North Dakota, South Dakota, Nebraska, Kansas
South	Texas, Oklahoma, Arkansas, Louisiana, Mississippi, Alabama, Tennessee, Kentucky
West	Montana, Wyoming, Colorado, New Mexico, Utah, California

Table 5. Demographic and Geographic Variables

Variable	Mean	Standard Deviation	Minimum	Maximum	Hypothesis
Total population (1970)	5,214	5,315	332	20,000	+
Total population (1990)	6,095	6,753	454	29,800	+
Total population (2010)	7,335	8,384	564	37,300	+
Population density	133	139	5.80	595	+
Population density in rural areas	30	25	1.7	93	+
% of population in rural areas	282	132	5.1	51.3	+
Miles of roads (1980)	188	104	58	561	+
Miles of roads (2008)	207	116	58	655	+
Miles of rural roads (1980)	154	75	36	435	+
Miles of rural roads (2008)	153	76	29	441	+
% of land federally owned	11.9	17.0	0.2	63.1	+/-

[141] These regions are based on US Census regional divisions, with some small changes to include states in the Marcellus shale gas play in the Northeast group.

Table 6. Oil/Gas Development Variables

Natural gas wells (2010) (log)	18	23	<1	95	+/-
Shale gas production (2009)	109	374	0	1,894	+/-
Conventional gas production (1970)	684	1,814	0	7,165	+/-
Conventional gas production (1990)	587	1,348	0	5,575	+/-
Conventional gas production (2010) (log)	704	1,380	0.43	6,744	+/-

Table 7. Geological and Hydrological Variables

Average annual rainfall	35	15	12	60	+
Average depth to groundwater	3,250	16,620	1	86,409	+
Induced seismicity events since 1981	2.26	4.91	0	24	+
% of the surface area that is covered by water	2.4	2.1	0.2	8.5	-
% of water consumed that comes from surface water	770	22.7	22.1	97.2	+
Bodies of water EPA-listed as impaired (2010)	909	1,346	111	6,957	+
Whether state overlies a major aquifer	0.33	0.48	0	1	+

Table 8. Economic Variables

State GDP (1980)	147	170	13	687	?
State GDP (1990)	192	239	15	1038	?
State GDP (2010)	313	396	31	1732	?
State GDP per capita (2010)	40	7.54	29	61	?
State GDP from tourism (1970)	215	294	25	1,441	+
State GDP from tourism (1990)	1,616	2,658	112	13,510	+
State GDP from tourism (2010)	11,433	15,615	978	76,439	+
% state GDP from tourism (2010)	3.8	0.9	0.4	5.4	+
Year-end budget balance (1978)	228	704	-38	3,686	?
Year-end budget balance (1990)	167	209	-310	702	?
Year-end budget balance (2010)	84	1,188	-5,342	2,302	?
Year-end budget balance (2010), normalized by GDP	0.2	0.3	0	1	?

Table 9. Political Variables

Political party of Governor	0.67	0.48	0	1	-
% population voting Republican in 2004 presidential race	0.78	0.42	0	1	-
% population voting Republican in 2008 presidential race	0.59	0.50	0	1	-
% population identifying as Democrat	42	6.31	26	54	+
% population identifying as Republican	42	6	32	58	-
Contributions to environmental NGOs (1990)	31	48	0.59	201	+
Contributions to env. NGOs (2010)	195	269	12	1,090	+
Contributions to env. NGOs per capita (2010)	28	20	4	83	+
Contributions to env. NGOs per Democratic voter (2010)	0.70	0.57	0.10	2.29	+

Table 10. Other Environmental Variables

% of land area forested	37.8	23.2	1.5	78.6	+
Number of threatened/endangered animal species (2012)	29	26	8	111	+
Number of threatened/endangered plant species (2012)	14	33	0	178	+
Species per square mile	0.06	0.05	0.02	0.25	+

6.3 Methodology

With almost 50 variables that can be associated with four measures of state rulemaking, the task of finding meaningful associations through regression analysis is potentially enormous. To make this task manageable, we narrowed our focus by defining and following a set of protocols.

We first targeted associations between independent and dependent variables for regression analysis by examining bilateral associations in a matrix of correlation coefficients and highlighting those with coefficients above an (arbitrary but consistent) cutoff. We experimented with different cut-offs, and did further experiments in which we tested variables with coefficients below the cutoff. This approach allowed us to focus our regression analysis on the strongest associations before we looked for patterns of associations among a set of variables.

We also took note of independent variables that are highly correlated with one another. Here, we used an arbitrary correlation coefficient of 50 percent or more to determine which variables to group together. A good example of variables that correlate with each other is the number of endangered plant species and the number of endangered animal species in a state: states with more (or less) of one tend to have more (or less) of the other. Another is gas production in one year and in another year. In general, we want to include only the best performing (see below) variable in a set of highly correlated variables in regressions.

Finally, we analyzed the independent variables using a three-step selection process. First, we analyzed variables that we hypothesized might be associated with all regulatory elements: a good example is GDP per capita, which could in principle affect a state's general ability or willingness to regulate. These "top-level" variables were analyzed first and kept in regressions according to the performance of the regression (its adjusted R^2) and whether the variable was significant at the 90 percent level or better.

Second, we analyzed variables that we hypothesized might be associated with either of the two major subsets of regulatory elements in our analysis—those aimed at protecting water quality/quantity, and those aimed at protecting air quality. For example, differences in average rainfall could in principle be associated with different surface or groundwater-related regulations, but this variable is probably not associated with regulations unrelated to water. In adding these variables, the same performance criteria were used as for top level variables, with attention paid to whether adding such variables affected the size and significance of the coefficients on the included top-level variables.

To do this targeting we created interaction variables. These variables combined one of the above variables with a dummy variable[142] for one of two subsets of regulatory elements discussed above (regulations related to air quality and those related to water quality). To disentangle the effects of the dummy variable by itself and the "main" variable, as well as the interaction between the two, all three variables must be introduced into the regression as well. [143]

Third, we tested the performance of surviving variables against further subsets of the elements in our analysis—regulations relevant to groundwater quality and to surface water quantity/quality. One or the other of these two sets was tested in place of the broader general water quality/quantity subset, and the regressions re-run. As above, we used interaction variables for this process.

In the following descriptions of our results, we identify, for each statistically significant independent variable, whether it is associated with all regulatory elements, or one of these subsets.

This hierarchical approach allows us to focus on variables that are associated with the broadest group of regulatory outcomes. In other words, it allows us to identify variables with the greatest potential explanatory power and to tell the simplest story possible.

6.4 Results

6.4.1 Regional Variables

Section 5 describes some of the geographical differences associated with how a given regulatory element is regulated. These differences can be described a bit more systematically and quantitatively using a regression approach. The idea is to regress dummy variables for each region (Marcellus, South, Midwest and West) against our four measures of regulatory activity (the number of regulations in a state, the tools the state uses to regulate, and the stringency of the state's quantitative regulations (where we use two alternative methods for this quantification). Finding significant relationships could imply that "neighbor" effects exist, i.e., that states contiguously located or in the same regional associations adopt similar regulatory strategies.

[142] A dummy variable takes the value of one for regulations in the set and a value of zero for regulations outside the set.
[143] Additional explanation might make this clearer. When we find an association between an interaction variable and a regulatory metric, a clean interpretation of the effect requires us to include separately the variables that make up that interaction variable. For instance, if we find that the rural population density is associated with stringency of the water-related regulations, this means in the regression analysis that we found a significant association between our measure of stringency and an interaction variable consisting of a dummy variable for the water-related regulations multiplied by the rural population variable. In this case, we also need to add separately to the regression the dummy variable and the rural population variable.

We found little evidence for such effects. Only associations between geographical groups and the number of elements regulated by states in those groups are statistically significant (in other words, we found no significant associations between regional groups and either states' choice of regulatory tool or the stringency of quantitative regulations).[144] Specifically, states in the Midwest and West generally regulate more elements among those we examined than states in the Northeast/Marcellus group and the South (see Table 4 above showing which states are included in each region). Note, though, that states within any group can be quite heterogeneous in their regulatory behavior.

6.4.2 Regression 1. Number of Elements Regulated

For the remaining (that is, non-regional) independent variables, we first tested the relationship between these variables and our simplest regulatory metric—the number of elements a state regulates (see Table 1). Our best-specified regression (meaning that in which the variables are robust to changing specifications, are not closely correlated with one another, and are significant), is shown in Table 11.

Table 11. Regression Results for Regulated Elements

Association	**Coefficient (p-value)**
All regulatory elements	
Natural gas wells (2010) (log)	0.018***
Contributions to environmental NGOs per Democratic voter (2010)	-0.042
% of water consumed that comes from surface water	0.001*
Number of threatened/endangered animal species (2012)	-0.003***
Water-related elements	
Water-related elements dummy	0.314***
Interaction of above two variables	0.003***
Prob. > F	0.00
Adj R^2	0.28
Observations	567

Notes: significant at: *=10% level; **=5% level; ***=1% level, NGO, non-governmental organization.

Interpreting these results, states with more natural gas wells in 2010 tend to regulate more of the elements in our analysis. In fact, this relationship is evident in our summary statistics presented in Section 4.2.1 above. In Figure 4, note that the five states with the most natural gas wells (Texas, Oklahoma, Pennsylvania, Ohio, and West Virginia) all regulate more elements than the national average. This relationship is small in magnitude, but statistically significant.

The degree to which Democratic voters contribute to environmental non-governmental environmental organizations (NGOs) is *negatively associated* with regulation of more elements, but in this specification is insignificant. This effect is significant occasionally. We left it in this specification to

[144] Note, however that we did find a statistically significant association between the percentage of land in a state owned by the federal government and the stringency of quantitative regulations. Given the lack of significant association of the regional groups with stringency, this variable does not appear to be a proxy for whether a state is in the West where federal land ownership is high.

illustrate a possible case of reverse causation. Perhaps Democratic voters in states that regulate fewer elements feel that more regulation is needed, and contribute to environmental NGOs in part to influence their state governments—in other words, it could be that the extent of regulation is the cause and donations are the effect, rather than vice versa.

A few other variables that could be related to environmental risks are associated with regulation of more elements, but interpreting the variables is somewhat puzzling. The interaction variable with endangered animal species has a positive sign. This means that states with more endangered or threatened animal species are likely to have more water regulations. However, looking at the species variable by itself, states with more endangered/threatened animal species are *less* likely to regulate overall.[145] Given that the size of these two effects is about equal, this means that the positive effect we see in the interaction variable is cancelled out for the water regulations.

Two additional variables are significant. The probability that a state will have a water regulation is greater than the probability it will have other types of regulations, other things equal (this is the dummy discussed in the previous paragraph). And states that get more of their water from surface sources are more likely to regulate elements related to water.[146]

These variables explain a bit under 30 percent of the variation in the number of regulatory elements present.

6.4.3 Regression 2. Choice of Regulatory Tool

As noted above, command and control is the predominant regulatory tool across the elements in our analysis, accounting for 81 percent of observed regulations (and 63 percent of all observations, including those for which we found no regulation). To test whether any variables are associated with states' choice of regulatory tool, we therefore divided states' regulations into two categories—command and control and all other types (primarily case-by-case permitting and performance standards). Elements for which we found no evidence of regulation were excluded from this analysis.

This dependent variable was then compared to the same list of independent variables (see Table 12). As noted, we had no strong hypotheses about relationships between these variables and states' choice of regulatory tool. This is because no regulatory tool is necessarily more stringent, onerous, or effective than another. This does not mean that the choice of tool does not matter—as discussed above, economists prefer performance standards on efficiency grounds, and case-by-case permitting has high administrative costs and lacks transparency, though it does maximize flexibility, among other considerations. Nevertheless, we see little reason why any of the independent variables we tested would be related to these considerations.

[145] The negative effect of endangered animal species on the likelihood of regulating is not what we expected. As with NGO donations by Democrats, this negative effect for endangered species is possibly a case of reverse causation, i.e., that states regulating fewer elements have *caused* a greater endangered/threatened species problem. If this finding were to withstand scrutiny it would be highly charged. Alternatively, this could be a case of omitted variable bias, where we see an effect but what is driving it is another variable that is not in our analysis but that is correlated with the species variable and the number of regulations variable. For now, all we can say is that there is an association that bears closer examination.

[146] This finding is not precisely what we expected, either. One might expect such states to be more likely to regulate surface water risks specifically, rather than all water-related risks (i.e. including elements primarily aimed at protecting groundwater as well). But there is no significant relationship with surface water regulations alone, while one does exist for all water regulations.

Table 12. Logit Regression Results for Use of Command and Control Regulation

Association	Coefficient (p-value)
All regulatory elements	
Conventional gas production (2010) (log)	-0.082*
Population density in rural areas	0.008
Water-related elements	
Water-related elements dummy	2.361***
Interaction of above two variables	-0.024*
Prob. > Chi^2	0.000
Log likelihood	-181
Pseudo R^2	0.09
Observations	444

Notes: significant at: *=10% level; **=5% level; ***=1% level.

States with greater conventional gas production are more likely to use command and control regulation. Also, states are *less* likely to use command-and-control for water quality-related elements. However, states with greater population density in rural areas are more likely to use command and control for the elements related to water quality. Overall, the former effect dominates statistically. But note that saying that water-related regulations are less likely to be command and control says nothing about the underlying factors influencing this choice.

These variables explain about 9 percent of the variation in states' choice of regulatory tool.

6.4.4 Regression 3. Stringency of Quantitatively Regulated Elements

As discussed in Section 4.2.3, it is possible to measure and compare the stringency of elements that states regulate with quantitative command-and-control regulations. We tested whether any of the "independent" variables are significantly associated with this observed variation in stringency. Recall that there are two alternative ways to measure a state's average stringency—either by ignoring those elements for which we found no evidence of regulation and measuring only the quantitatively regulated elements (Method 1) or by treating unregulated elements as minimally stringent (Method 2). We did separate regressions for each measure.

After many regressions, we found only one general variable associated with stringency across all elements for method 2 (the percentage of federally owned land in a state) and none for method 1. For subsets of our regulatory elements, we found only one interaction variable with a significant association with Method 1 stringency, and two interaction variables with a significant association with Method 2 stringency. These two regression results are shown in Table 13 and Table 14.

Table 13. Regression Results for Method 1: Stringency of Quantitative Elements (ignoring unregulated elements)

Association	Coefficient (p-value)
All regulatory elements	
% of land federally owned	-0.002
Water-related elements	
Water-related elements dummy	-0.017
Interaction of above two variables	0.006*
Prob. > F	0.15
Adj. R^2	0.01
Observations	200

Notes: significant at: *=10% level; **=5% level; ***=1% level.

Table 14. Regression Results for Method 2: Stringency of Quantitative Elements (treating unregulated elements as minimally stringent)

Association	Coefficient (p-value)
All regulatory elements	
% of water consumed that comes from groundwater	-0.000
% federally owned land	-0.002*
Water-related elements	
Water-related elements dummy	0.292***
Interaction of above two variables	0.005*
Groundwater-related elements	
Groundwater-related elements dummy	-0.160*
Interaction of above variable with % groundwater consumption	0.005**
Prob. > F	0.00
Adj. R^2	0.17
Observations	292

Notes: significant at: *=10% level; **=5% level; ***=1% level.

A greater proportion of federally owned lands in a state is associated with more stringent regulation of elements related to water. This association is significant under both methods of calculating stringency, but the effect is somewhat larger with Method 1. Also, the significance of the water regulation dummy variable for Method 2 means that this interaction effect indicates that water regulations tend to be more stringent than other regulations, other things equal. However, having a greater percentage of federally owned land in a state is associated with weaker standards overall. Since, as noted earlier, we found no significant association between regional groups and regulatory stringency, we can conclude that this result is driven by variations in federal land ownership outside of the western states (which have particularly high levels of federal land ownership) as we have defined them.

In addition, for Method 2, we found that the percent of groundwater used for water consumption in the state is significantly associated with more stringent groundwater quality regulations. Overall, however, groundwater regulations tend to be less stringent than other types of regulations. Pairing this finding with the finding that *all* water-related regulations tend to be more stringent than other regulations, the inference is that surface water regulations tend to be more stringent than groundwater regulations.

Only 1 percent of the variation in stringency calculated with method 1 is explained. The percentage rises to 17 percent under method 2. Thus, treating unregulated elements as minimally stringent improves our ability to explain the heterogeneity we observe.

6.5 Observations

Our most statistically significant and robust result across all the elements in our sample is that states with more gas wells tend to regulate more broadly—that is, they have at least some regulation for more of the elements in our analysis. This may reflect the fact that a larger industry presence gives states more reason to regulate. States with more production also tend to rely more on command and control approaches to regulation. This could be due in part to the relatively low administrative costs associated with command and control regulation, which are especially important if dealing with a large industry presence.

When we analyzed subsets of the regulatory elements in our analysis, we found that states are more likely to regulate elements related to water quantity and quality, and that these elements are less likely to be regulated with command and control tools than other elements. However, when states do regulate these elements quantitatively (which in most cases implies command and control regulation), they regulate more stringently on average than they do for other elements. If we further divide water-related elements into those aimed at protecting surface and groundwater, we find that this increased stringency is being driven entirely by surface water-related regulations—groundwater-related regulations are *less* stringent on average.

Turning to the environmental variation often cited as justifying regulatory heterogeneity across states, we found few significant associations. Evidence suggests that states that rely more on surface water are likely to have more water regulations, and that those that rely more on groundwater are likely to have more stringent groundwater regulations. These findings may be an important example of regulatory heterogeneity being driven by local conditions related to environmental risk.

Otherwise, however, the only environmental variables we found to be associated with the heterogeneity we observed is the number of endangered animal species. Effects on species via habitat fragmentation have been raised by some as an important impact of shale gas development, but have not received the public attention that other risks—primarily those to air and water quality—have. And where we did find an effect for endangered animal species, it is limited to water-related regulatory elements and is in the opposite direction from what we hypothesized—a greater number of species is associated with regulating *fewer* elements. As noted above, this could be an example of reverse causation or omitted variable bias, but we hesitate to back any particular interpretation.

Similarly, no demographic variables yielded significant associations with the presence or stringency of regulation. Only one political variable did so: donations to environmental NGOs by

Democrats, although in our preferred specification this was not significant (to the extent it is significant in other specifications, it may be evidence of reverse causation).

We did find evidence of an effect of the share of federal land on regulatory stringency—a greater percentage of federal land in a state is associated with less stringent water-related regulations, at least when unregulated elements are treated as minimally stringent (Method 2). We have discussed a few hypotheses for why this effect appears, but to us none seem plausible.

Generally, therefore, we find it surprising and certainly interesting how few of the variables we examined are associated with the heterogeneity we observed in a statistically significant way. In particular, it is interesting that few environmental variables we tested show statistically significant associations, because such differences among states are often put forward as justifications for state-level oil and gas regulatory heterogeneity.

Although we cannot conclude that the statistically significant relationships we did identify are causative, the lack of significant associations for many of the variables we tested is evidence against causation. However, as noted, this and any inferences from these regressions are limited to the data in our analysis.

In other words, it is possible that geological and hydrological differences among states (or other variables) are the reason for regulatory heterogeneity, but that we failed to find evidence of this due to the limitations of our analysis. It may be that other variables we did not test would be associated with the heterogeneity we observed, or that the variables we did test would be associated with a broader measure of regulatory heterogeneity that included more elements. We welcome such further investigation of the roots of heterogeneity.

7. Conclusions

The regulation of shale gas development is complex and dynamic. Its complexity comes from the multiple layers of government involved and from regulatory structures, approaches, coverage, and stringencies that vary across the states. Its dynamism comes from the rapid pace of shale gas development itself, which has left some legislatures and regulators scrambling to catch up. Even in states that have regulated oil and gas development for decades, such as Texas, the special challenges associated with fracking and, possibly, changes in public tolerance for environmental risks have led to changes in regulation. The federal government has also struggled to keep pace: The Bureau of Land Management (BLM) has been working to develop updated regulations for shale gas development on federal lands, and EPA has been conducting research and writing regulations for the risks within its jurisdiction.

Because states are the primary (albeit not exclusive) venue for shale gas regulation, this report has focused on regulations in 31 states with at least some related activity. Of these states—which we analyzed statistically as well as descriptively—27 have had active natural gas production at least since 2010.

7.1 Heterogeneity

The most significant finding from our analysis is the extensive regulatory heterogeneity among the states. States with active gas production vary significantly in the number of elements they regulate—some regulate less than half of the 21 regulatory elements we tracked statistically, whereas others regulate all but one. States rely on qualitative and technology-based command-and-control approaches as well as numerical standards, performance-based approaches, case-by-case permitting, and bans and moratoria. Command-and-control regulation is the most prevalent tool, with states using it for 87 percent of regulations (64 percent of all observations, including those for which no regulation was found) across elements considered. Stringency varies greatly as well, as much as an order of magnitude for some elements, though others are more consistent among states.

However, there may be good reasons for regulations to differ among states. Geology, geography, history, demographics, economic conditions, and other factors may lead states to justifiably make different regulatory decisions. Fully explaining this heterogeneity is difficult, perhaps impossible, and in any case beyond the scope of this report.

Nevertheless, we did use regression analysis to examine heterogeneity, identifying 48variables that, we hypothesized, could be related to the regulatory heterogeneity we observed. Relatively few statistically significant associations emerged.

Among the associations we did find, the most significant and robust relationships are the positive associations between the level of state gas development and the number of elements regulated by the states. The environmental variables most often cited as justifying regulatory heterogeneity across states yielded a few significant associations. States with a greater reliance on surface water appear to regulate more elements in our analysis. Otherwise, significant associations with environmental variables are limited to subsets of the elements in our analysis—perhaps most notably, states' relative dependence on groundwater appears to be associated with the stringency of those regulations. We also discovered a few additional significant but puzzling associations that may be examples of reverse causation or omitted variable bias, as discussed above.

We consider these findings interesting, if not necessarily surprising. But they cannot explain much of the regulatory heterogeneity we observed. This could be due to the limitations of our analysis. Our list of independent variables is far from perfect—we may have failed to test important sources of heterogeneity. Associations may have been stronger (or weaker) had we been able to include unobserved factors, such as the real-world stringency of case-by-case regulations or the effectiveness of enforcement. And, of course, the elements in our analysis are only a part of states' regulations relevant to shale gas development. A larger sample might yield significant associations that ours did not.

Nevertheless, our general failure to find more than a few significant associations between regulatory heterogeneity and underlying differences among states may shift the rhetorical burden of proof to those who claim that such relationships do exist. Given the limitations of our analysis, our findings are certainly rebuttable, and we welcome attempts to do so. But they do draw common claims about the roots of regulatory heterogeneity into question. We look forward to further analysis of this question. Our regulatory database can be made available for such testing.

We hope our analysis will inspire dialogue among states and regulator self-examination about why regulations are written the way they are and whether they can be improved to better fit local conditions, to be more efficient, and to reflect the latest technologies and thinking about regulatory design.

7.2 Other Findings

Beyond heterogeneity and attempts to identify its sources, our review reveals two other important findings.

First, as noted above, shale gas regulation is marked by rapid change. This made describing regulation a challenge, as it is always a moving target. Almost all states are changing their regulations, some quickly. New regulations are generally, but not always, more stringent than their predecessors. We did not observe general convergence, though there are some examples, such as convergence among states toward fracturing fluid disclosure using the US Department of Energy-supported FracFocus website.

Second, shale gas regulation suffers from a lack of transparency. States vary greatly in terms of how difficult it is to determine relevant regulatory requirements from their regulations and/or state code. We found that relevant provisions are often scattered throughout the code or appear only in uncodified regulations, which may be difficult to find or may even be contradictory. In a narrow sense of the term, all or almost all state regulations are transparent—they are publicly available if you know where to look (or look hard enough). But in some cases they are much harder to find than they should be—as evidenced by regulations in those states that do a good job of making regulations clear and accessible.

Moreover, some regulatory tools are opaque by nature. Case-by-case permitting has advantages, and there is little reason to believe it is less stringent or less effective than more open tools such as command-and-control or performance standards. But without reviewing masses of permit applications and decisions, it is impossible to know how stringent or how effective permitting processes are.

These two forms of regulatory opacity—opacity by design and opacity by poor design—are a significant barrier for stakeholders, whether they are firms seeking to comply with the law or interested members of the public trying to understand it in light of environmental risks. Firms can generally adapt to lack of transparency by hiring consultants. This is arguably a misallocation of resources, but at least firms have this option. The public generally lacks access to such expertise, except to the uneven extent that journalists, activists, or researchers can invest the time and resources necessary. Policymakers should therefore work to improve the transparency of their existing regulations and should treat transparency as an important consideration when choosing among regulatory tools.

A related issue is how effectively regulations are enforced. Many states face fiscal shortfalls, and many state oil and gas regulators struggle to retain qualified staff in light of higher salaries available in the private sector. Both trends make effective enforcement more difficult. As noted above, this report studies only stated regulations, not enforcement, but the two are equally important parts of real-world regulatory stringency and effectiveness. There is a great need for more research in this area.

Regulators, and indeed most stakeholders, are interested in identifying the “best” regulatory options—that is, those regulations that offer the greatest reduction in environmental and other risks associated with development for the lowest cost. This report is an important first step in that inquiry, but it is only the first step. Here, we describe what the current regulatory environment is and take some first steps toward explaining why states are making the regulatory choices they make. But that is at most only a third of the picture. As noted, understanding enforcement is crucial. But, ultimately, research is needed on the cost and environmental outcomes associated with regulations. These three pieces together will, in theory, make it possible to identify ideal regulations and best practices, or at least to make meaningful comparisons. In the meantime, however, development continues. Regulators must do the best they can.

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