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Shale Gas Development: A Smart Regulation Framework

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ABSTRACT: Advances in directional drilling and hydraulic fracturing have sparked a natural gas boom from shale formations in the United States. Regulators face a rapidly changing industry comprised of hundreds of players, operating tens of thousands of wells across 30 states. They are often challenged to respond by budget cuts, a brain drain to industry, regulations designed for conventional gas developments, insufficient information, and deeply polarized debates about hydraulic fracturing and its regulation. As a result, shale gas governance remains a halting patchwork of rules, undermining opportunities to effectively characterize and mitigate development risk.

The situation is dynamic, with research and incremental regulatory advances underway. Into this mix, we offer the CO/RE framework—characterization of risk, optimization of mitigation strategies, regulation, and enforcement—to design tailored governance strategies. We then apply CO/RE to three types of shale gas risks, to illustrate its potential utility to regulators.

■ INTRODUCTION

This paper offers a framework for evaluating and shaping shale gas governance strategies. CO/RE identifies where cooperation can be helpful, and when mandates are necessary. CO/RE also builds on adaptive management strategies of data gathering, learning, and reassessment, to keep pace with technology and our understanding of the risks. The framework raises key questions about early efforts to govern shale gas, and suggests paths forward.

Advances in directional drilling and hydraulic fracturing have made it possible to recover gas directly from low-permeability shale rock. The federal Energy Information Administration (EIA) only began collecting data on proved shale gas reserves in 2005; by 2011, shale gas represented two-thirds of domestic proved natural gas reserves.[1,2] Shale gas represents one-third of total natural gas production today,[2] and is projected to constitute 49% of total production by 2035.[3] Regulators face a rapidly changing industry, comprised of hundreds of players, operating tens of thousands of wells across 30 states.

Shale gas development is larger in scale and more intense than conventional development, and is occurring in urbanized areas[4] and regions unused to large-scale oil and gas extraction.[5] Table 1 demonstrates the material requirements of Marcellus shale gas wells as compared to conventional natural gas wells. The Marcellus formation extends from West Virginia into New York, and forms the epicenter of Eastern U.S. natural gas production.

Some of the environmental risks posed by shale gas production are common to all natural gas production, but are greater or more apparent given the scale and location of shale

Table 1. Conventional Versus Marcellus Shale Gas Development [6]

	Conventional	Marcellus Shale
Drilling:		
water use	116 514 gallons	199 924 gallons
steel	55 t	145 t
cement	115 t	239 t
Completion:		
water use		3.8−5.5 million gallons
sand		6 million pounds
chemicals		5,709 gallons

gas activities. Other risks are particular to shale gas development. Consensus is emerging around some key risks: surface water contamination and habitat disruption from construction; methane and volatile organic compounds (VOC) air pollution; freshwater depletion; surface water contamination from fracturing fluid spills and wastewater discharges; surface water and groundwater contamination by leaking wastewater impoundments; and contamination of groundwater from poorly constructed or maintained wells.[7] Still, there are things we still do not know about the extent of these risks, their

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probability of occurrence, and the optimum mitigation strategies. Without more complete data sets and real-time monitoring, regulators are challenged to respond appropriately.

Despite good intentions and hard work, the result has been a halting patchwork of rules. For regulators and industry, this situation represents missed opportunities to effectively characterize and mitigate development risk.

CHARACTERISTICS OF THE SHALE GAS INDUSTRY

Shale gas production is a tough regulatory target for five reasons. First, actors in the natural gas industry range widely in their ability to absorb new regulatory requirements. Operators range from the world's largest multinational companies with diverse energy investments, to small family owned outfits operating a single well. Over 70% of the work at a typical well may be handled by contractors, including drilling companies, hydraulic fracturing service companies, chemical suppliers, waste haulers, water purveyors, and cement contractors.[8]

Second, the sources of potential pollution—including wells, compressors, storage tanks, wastewater impoundments, and gathering lines—are relatively small, geographically dispersed, and numerous. Inspecting millions of smaller sources is much more resource intensive than, for example, inspecting 557 coal-fired electric power plants.[9] Compliance determination becomes a frustrating and necessarily arbitrary process, compounded by public sector budget cuts, and loss of key agency personnel to industry.

Third, oil and gas governance is dispersed. Oil and gas operations are exempted from many federal environmental requirements.[10−12] The federal government has taken some steps where it has jurisdiction; for instance, the federal Environmental Protection Agency (EPA) requires greenhouse gas emissions reporting from oil and gas wells[13] and "green completions" of natural gas wells to cut VOC and methane emissions.[14] Federal agencies have contemplated additional action as well.[15−20] However, traditionally states have been the primary regulators of the oil and gas industry,[21] and likewise they have led the charge on shale gas governance.[22−24] Supporters of this framework argue that states enjoy considerable expertise in this area, and can design oil and gas requirements to fit local circumstances. Nevertheless, a state-led regulatory model also results in different standards from state to state.[38] Meanwhile, some cities and towns have banned hydraulic fracturing altogether.[25] Others have enabled the activity to proceed but with road use limitations,[26] noise restrictions, and exhaust capture requirements.[27] Some states have sued local governments to limit their actions.[28]

Even within levels of government, governance is shared by multiple agencies.[29] Decentralized governance can undermine risk detection and response, unless "information flows freely across departmental boundaries".[30] Broad distribution of regulatory power may also weaken each agency, feeding the public's concern that oil and gas activities are under-regulated.[31] [32]

Fourth, the oil and gas industry often resists regulation, adding transactional and political costs to regulatory proposals. Larger players may oppose changes to regulation because they can; smaller actors may fight new rules because they do not have the expertise or profit margins to invest in appropriate environmental, health, and safety measures. Profit margin and competitiveness concerns are particularly acute now, with natural gas prices at low levels.[33] Resistance to regulation becomes a defensive posture, cultivating a broader reluctance to acknowledge risk or embrace governance innovations. As a result, the oil and gas industry continues to innovate below the earth's surface while remaining mired in conventional thinking above. Meanwhile, while new regulation is debated, agencies attempt to apply rules designed for conventional natural gas development to shale gas operations.[24,34]

Fifth, we face significant data gaps about shale gas development. Regulators may permit activities without knowledge of key risk drivers; for instance, in many states, drilling permit applications do not ask about the chemicals that will be onsite and used downhole.[35,36] Consistent risk assessment methodologies are lacking.[37] And many states appear to be crafting shale gas rules without knowing about similar rules issued in other states.[38,39]

Efforts are underway to address these gaps. Some states have halted or delayed shale gas permitting to conduct risk studies.[40−42] Other states use Risk-Based Data Management Systems (RBDMS) to gather oil and gas development data.[43] Agencies, industry, and NGOs are assessing shale gas impacts on drinking water resources,[44] documenting silica exposure,[45] and estimating methane leakage rates from gas wells, associated equipment, and pipelines.[46,47] Companies have joined collaborative efforts to craft environmental solutions, for instance through EPA's Gas Star program,[48] develop "compliance-plus" certifications,[49] and share best practices with regulators.[50] However, while these steps represent progress, they fall short of a cohesive, coherent information gathering framework based on uniform standards and data sharing.

GOVERNANCE THEORIES AND THE CO/RE FRAMEWORK

The characteristics of shale gas development make it difficult to engage in "smart regulation".[51] At the same time, this regulatory challenge has sparked numerous policy proposals. Members of Congress have introduced legislation to aggregate shale gas sources of air pollution, to trigger additional action under the federal Clean Air Act.[52] Academics are debating whether the federal government should take a larger role in regulating shale gas, to consolidate governance and set uniform minimum standards across the country.[53,54] And in response to the lack of data, one scholar has suggested reviewing state enforcement of existing oil and gas laws to spot shale gas risk patterns and prioritize regulatory responses.[55,56]

These proposals are unfolding within a broader conversation about governance and regulatory theories.[5760] Adaptive management theory may be particularly relevant here.[57,58,61] Adaptive management "allows agencies to learn about and respond to changing conditions at the "back end" rather than loading all decision making at the "front end", when the effects of decisions and of other changing conditions are not yet known".[57,62,63] The approach is useful when risk "emanates from a multitude of diverse, dispersed sources responding to coevolving interactions, feedback loops, and nonlinear cause-and-effect properties".[57] On the other hand, adaptive management is not necessary unless "information gaps limit resource managers' ability to evaluate [governance strategies]. Absent such uncertainties, managers could confidently act on the basis of front-end knowledge".[64]

Adaptive management is often presented as a dichotomy with traditional "front end" regulation. However, regulators must rely on both approaches to effectively govern shale gas development. Some of the risks posed by this activity are multifaceted, for instance, methane leakage from the life cycle of natural gas and its relative impact on man-made climate change. Others have more direct causes, for instance, surface water contamination from a chemical spill.

We offer the CO/RE framework as a way to move beyond the dichotomy suggested by the literature. CO/RE—characterization of risk, optimization of mitigation strategies, regulation, and enforcement—combines adaptive management and traditional regulatory theory. We have not invented these steps; each describes an established approach to governance. However, sometimes approaches appear to have been selected indiscriminately. CO/RE helps a regulator determine the best initial approach to a risk. The framework also identifies where cooperation can be helpful—to gain access to information about risk, or to leverage private sector expertise in shaping a response—and where mandates are necessary—to set clear, uniform standards and hold regulated entities responsible for compliance. The four steps of the CORE framework are as follows:

1. Characterization of Risk. Effective governance of shale gas development requires understanding of risk and its root causes. Information can shrink the gap between actual and perceived threats, focusing regulatory efforts where they are needed most. [65]

Collaboration is particularly useful at this step. Firms have access to information that can spot risk, quantify its probability and impact, and identify causes. Down the road, this partnership may also ease resistance to regulation.[66] Participation by multiple agencies can leverage relative strengths and avoid regulatory overlap;[67] encouraging these partnerships early on can make governance more effective throughout the CO/RE cycle. NGO partners, meanwhile, can offer environmental expertise and help to validate the process to the public.[68] And involvement of diverse stakeholders builds trust in their respective circles that the resulting information will be reliable.[64] Paramount in a highly politically charged environment, the collaborative process creates a "problem solving" atmosphere that allows stakeholders to focus on solving the problem rather than defending their positions.

Induced seismicity is a potential shale gas risk that agencies could begin to address at step one. An uptick of earthquakes in regions where the underground injection of shale gas wastewater is occurring[69,70] suggests a correlation. However, causation and the risk drivers have not been established with any confidence.[71] Working with industry could provide agencies with access to injection wells and operators, to determine whether certain conditions or actions trigger earthquakes. Moreover, by bringing wastewater disposal companies into the conversation, agencies can develop a productive dialogue with these entities.

2. Optimization of Mitigation Strategies. After characterizing a risk and identifying causes, governance efforts can focus on risk mitigation. Possible solutions may include operational standards, management strategies, or technologies to measure or reduce pollution. Collaboration with industry is helpful at this step, too, for technical expertise and an understanding of the culture that solutions will have to penetrate. Alternatively, to advance certain public policy goals, agencies may offer grants, tax credits, or other incentives to drive private-sector innovation. For instance, in 1980, the United States began offering a production tax credit to spur innovation in unconventional oil and gas production and reduce America's dependence on foreign sources of energy.[72]

Whether step two innovation occurs through collaboration or using government incentives, test conditions, costs, and results should be tracked and shared to enable evaluation and replication. Moreover, measurement and monitoring systems should be used to determine how quickly industry players are adopting the measures, and whether deployment is reducing risk.

Cooperation with other stakeholders may be helpful at this stage as well. Risk information developed in step one can inform insurance industry risk models.[73] Insurance pricing that more accurately reflects risk can serve as a risk mitigation strategy, by creating a structural incentive for companies to modify their behavior.[59]

Several aspects of shale gas wastewater management currently fall into step two. For instance, it is known that improperly treated wastewater released from wastewater treatment facilities can have deleterious effects on surface waters.[74] EPA has considered setting pretreatment standards for wastewater into and out of wastewater treatment facilities (WWTF)[15,16] Yet the agency acknowledges that many WWTF employ technologies "not designed to treat high levels of total dissolved solids (TDS), naturally occurring radioactive materials (NORM), or high levels of metals".[16] While EPA may propose standards in 2014,[16] a more promising path forward might be focused collaboration to optimize effective treatment methods.

3. Regulation. Regulation is often necessary to ensure consistent data collection, normalize best practices, and provide a level playing field. This may be particularly important in the shale gas context, where low commodity prices drive cost-cutting measures,[75] and where smaller operators may not have the knowledge or the wherewithal to adopt voluntary best practices. Regulation may deploy proven, cost-effective mitigation strategies—perhaps ones developed through collaboration—or encourage technological innovation. It may take the form of "command-and-control" rules or flexible performance standards.[76] Agencies could also consider offering regulatory incentives such as lower bonding requirements or streamlined permitting. The test is whether the regulation effectively drives the industry to achieve desired outcomes.

EPA took what it learned about methane emissions control under a step two collaboration, and used it as the basis for air rules that apply to natural gas wells and associated equipment.[14] As detailed below, despite having developed a cost-effective technology to control methane emissions at producing wells with industry, EPA recognized a barrier to implementation. Therefore, regulation was necessary to lock in the benefits of the developed "green completion" technology.[77]

Similarly, industry has developed best practices to ensure well integrity and reduce the risk of underground leakage of methane, fracturing fluids, and produced water.[78] Some natural gas companies and NGOs have advocated the inclusion of these practices into well integrity regulations, to ensure adoption of these practices by all operators.[79 80]

4. Enforcement. Enforcement provides credibility and builds the public's trust. Voluntary programs and reduced compliance detection programs for "good actors" are ways to develop mitigation strategies, educate the regulated community, and reduce the universe of enforcement targets, but enforcement is a necessary backstop to an effective governance regime.[81]

Critical to enforcement is the ability to detect non-compliance. If no one can tell who is complying with a

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regulation, the value of compliance and the incentive to comply diminish. At the same time, agencies cannot spend all of their limited resources determining compliance. While enforcement budgets should be increased, there will never be enough "boots on the ground" to conduct traditional enforcement of the shale gas industry.[82] Innovation and deployment of next generation compliance detection is therefore necessary, for instance through the use of "tracers" to fingerprint fracturing fluid,[83] electronic well monitoring,[84] and remote sensing technologies.[85] State and federal agencies can incentivize deployment of emerging measurement technologies in the settlement context.[86]

Shale gas waste management may be approached through step four. A number of waste management regulations exist at the state level. Some argue that these rules are not sufficiently stringent or well-tailored to shale gas waste.[87,88] While regulatory changes may be necessary, regulators may be flying blind without a better handle on the compliance status of well operators, waste haulers, and disposal companies. For instance, Pennsylvania authorities could not account for twenty percent of the wastewater generated in state, in 2009−2010.[89] Spills and waste impoundment leaks go unpunished, driving local concerns about the shale gas industry.[90−92] Improving enforcement of these rules is the best next step for addressing these water pollution risk drivers.

CO/RE allows regulators to enter at any step, to address a problem where they find it. The more that is known about a problem or a solution, the more likely it is that regulators can proceed to the third step and enact smart regulations. Where less is known, agencies may begin at step one, collaborating with industry to characterize risk and identify causes. If the resulting data disproves the existence of a risk, or if step two generates a solution that is adopted quickly, regulators may never need to proceed to step three. In this way, collaboration is not a parallel track or a way of avoiding regulation; it is a step in the process of evaluating the need for regulation and the selection of regulatory responses.

Finally, if regulators set standards and document a high rate of compliance with those standards, and yet observe a persistent risk trend, they may begin again at step one, looking for new risk drivers. This cyclical nature of the CO/RE framework enables a governance structure to evolve with technology and our understanding of the risks. It follows adaptive management principles[57] and echoes the call of a shale gas panel of experts for a "systematic commitment to a process of continuous improvement".[93] For instance, if methane measurements do not reflect a decrease in emissions after EPA's "green completion" requirements go into effect, EPA should revisit previous steps to identify additional sources of methane emissions in the shale gas industry and fill regulatory gaps.

Data gathering and analysis is critical through all four steps of the CO/RE framework. Wherever regulators enter the process, they should review existing information and spot data gaps. Conducting "an explicit information gap analysis" at the outset helps the regulator identify governance goals; focuses attention where learning would be the most helpful; and suggests sources of information.[64]

Regulators should also take the first collaborative opportunity to develop metrics for measurement and monitoring protocols. Consistent risk assessment methodologies, uniform metrics, and common protocols for gathering data in the field, would enable analysis of data between wells and across basins.[37] Similarly, research results should be harmonized and linked for efficient sharing and uptake of information. For instance, some have suggested collaboration to harmonize state RBDMS reporting, and link these platforms to U.S. Department of Energy data sets.[94,95]

■ APPLYING THE CO/RE FRAMEWORK TO THREE TYPES OF RISK

We begin by evaluating governance efforts in three categories of risks associated with shale gas developments, using the CO/RE framework. Then, we suggest paths forward. We do not suggest that these are the only or even the greatest risks associated with shale gas developments, but offer these as illustration of CO/RE framework's utility. CO/RE might also be applied to address other risks, from road damage and habitat fragmentation, to chemical exposure and threats to community character.

RISK: Contributing to Global Climate Change. One risk associated with shale gas development is the release of methane to the atmosphere. Methane is the primary dry component of natural gas. It is also a more potent greenhouse gas than carbon dioxide, triggering twenty-one times the warming effect over 100 years.[96] Scientific consensus about the existence of global climate change driven by human activity emerged in 1990, with the publication of the first IPCC Assessment Report.[97]

Characterizing the Risk. During the drilling and completion of a well, some methane can escape to the atmosphere.[98] Later, over the years that a well is producing, formation fluids occasionally accumulate in the wellbore. Operators use pumps or remedial techniques such as venting or "blowing down" the wells to remove these liquids. Operators may vent the methane entrained in the liquids to the atmosphere, or convert it to carbon dioxide and water by flaring it at the well.[99] Additional methane is lost through pneumatic devices and leaks in pipelines, storage tanks, compressor seals, and other equipment.

These releases are not specific to shale gas extraction. However, potential emissions may be greater for unconventional developments because of the large flowback of methane-rich liquids during well completion, and the lack of natural gas gathering infrastructure in new development areas.[100] Moreover, the simple fact of more natural gas development, and increased pipeline pressure to transport increased product volume, drives emission increases.[101] In 2011, an estimated 200 billion cubic feet (bcf) of methane was flared or vented in the United States from the natural gas sector.[102] National scale atmospheric studies indicate total annual methane emissions are 7−21 terragams (or 364−1092 bcf).[103]

Optimizing Risk Mitigation Strategies. Before the shale gas boom, EPA and the natural gas industry recognized the risks of methane emissions and rightly viewed these emissions as loss of valuable product. Therefore, in 1993, the agency and several natural gas transmission and distribution companies formed Natural Gas STAR, to develop and test methane reduction technologies. Two-thirds of the partners filed progress reports in 2012, describing nearly 100 technologies to reduce methane emissions by 85.9 billion cubic feet.[104] EPA convenes technical conferences and serves a clearinghouse function for effective methane reduction strategies.[105] One of these strategies is the cost-effective "green completion" process for capturing VOCs (and indirectly, methane) during the completion/flowback process.[106]

Regulation. Once companies realized the "green completion" process could pay for itself in recovered product, the adoption rate increased. However, many companies still declined to adopt the practice. Therefore, regulation was needed. In 2012, EPA issued Clean Air Act rules for oil and gas wells, requiring "green completions" at natural gas wells beginning in 2015.[14] The rules do not extend to methane released from oil wells.[14,107] The rules also require implementation of strategies—many developed through the Gas STAR partnership—to control emissions from compressors, new storage vessels, and new and modified pneumatic controllers.[14] Some industry participants have questioned EPA's emissions factors for hydraulically fractured gas well completions.[47,108] And industry groups have challenged the rules in federal court.[109] However, criticism has been relatively muted. While it remains to be seen if all Gas STAR partners stay with the program for its next phase, companies may realize that having a seat at the table and helping to develop cost-effective control strategies in advance of any rulemaking reduces compliance costs. In fact, several Gas STAR partners more recently worked alongside Colorado officials and NGOs to craft tougher methane rules for that state.[110]

Enforcement. EPA should work with states to identify best practices for determining compliance with the air rule. For instance, state inspectors will need to identify "new" (postrule) wells in the field to determine which are subject to the "green completion" requirements. States and EPA have already begun reviewing remote sensing technologies on the market, to find cost-effective options for agency inspectors conducting compliance reviews.[111,112] Moreover, as states prepare to enforce against venting of methane to the atmosphere, they may need to coordinate with local governments who have flaring bans in place.[113]

EPA may also be able to use its Greenhouse Gas Inventory and the growing number of methane emissions studies to track compliance with the air rules. EPA created the Greenhouse Gas Inventory in 2009;[14,114] oil and gas sources, including wells, began reporting in 2012. Alongside the Greenhouse Gas Inventory figures for the natural gas industry,[115] industry, NGO and academic studies are measuring methane emissions at wells, gas processing plants, gathering systems, transmission pipelines and other equipment.[116−118] The Inventory and the studies might help to identify noncompliant sources and facilitate enforcement. They may also suggest adjustments to emissions factors EPA assigns to sources for reporting and compliance purposes, improving the accuracy of reported data over time.

Moreover, these collective efforts may refocus limited agency resources on the risks that matter the most. For instance, the 2013 University of Texas production sector study[116] revealed lower methane emissions from some sources than EPA had estimated. However, measured methane emissions from equipment leaks and some pneumatic controllers were higher. This information, if borne out, could direct attention to these larger sources of emissions.

Meanwhile, "top down" studies, measuring methane emissions in the atmosphere rather than from sources on the ground, are reflecting potentially higher methane emission rates.[103,119] The Inventory and "top-down" studies can help EPA evaluate whether the air rules are sufficient for achieving real emission reductions. If they are not, regulators should revisit the risk drivers and shape new strategies in response.

CO/RE Analysis and Next Steps. EPA came to the problem of methane emissions already knowing about the risk and some of its causes. Therefore, EPA could enter the CO/RE framework at step two, and form a partnership with industry to optimize mitigation strategies in response to known problems. When solutions emerged, EPA proceeded to step three, writing air rules that locked in the benefits of those solutions and leveled the playing field across the industry.

EPA is currently at step four of CO/RE. The tendency might be for the agency to consider this risk addressed. However, our framework suggests the agency should focus on enforcement and honest program evaluation to find shortcomings in the governance structure. Some shortcomings may already be known. For instance, EPA limited the "green completion" requirement to new and refracked wells drilled principally for natural gas.[14,107] The limit excludes thousands of wells drilled for oil, leaving North Dakota to address a large methane emissions issue in the Bakken Shale.[120,121] Regulators may want to consider revisiting this exclusion. Likewise, EPA should evaluate whether to expand the air rules to regulate methane directly,which under the Clean Air Act would empower the agency to regulate hundreds of thousands of existing wells.[122]

Beyond EPA's air rules, there are a number of additional steps agencies could take to drive the development of mitigation strategies under step two. For instance, Colorado's methane rule does not limit companies to using EPA Method 21, instead enabling industry to detect equipment leaks use more cost-effective but equivalent methods.[123] At the distribution end of the spectrum, Pennsylvania and Texas have capped the amount gas companies can charge customers for lost and unaccounted for gas. This creates a market incentive to develop efficient systems for identifying and repairing pipeline leaks.[124,125] States can also incentivize distribution line repairs by guaranteeing some cost recovery.[126] In 2013, Senator Edward Markey (D-MA) introduced federal legislation encouraging both policies.[127] Finally, Gas STAR could take up some of these issues for its next phase of collaborative work.

Meanwhile, if the University of Texas study[116] results are confirmed, agencies should consider collaborating with industry or incentivizing development of better leak detection and repair (LDAR) systems and low- or no-bleed pneumatic devices. State agencies could require deployment of these emerging technologies as a condition in Clean Air Act settlements, to test their effectiveness.[86]

Framing efforts to detect and reduce methane leaks in economic terms—for instance, by describing methane emissions reduction in terms of "avoided carbon costs," "recovered product," and "energy delivery efficiency"—could provide a quantitative basis for insurers, lenders, shareholders, and Wall Street analysts to compare firms. Private sector risk analyses could drive further innovation in methane measurement and leak reduction technologies.

Finally, to avoid catastrophic climate change, we will need to innovate not only in how we get oil and gas out of the ground, but in how we use these fuels. Step two could be an entry point for tackling this issue, using incentives to develop and optimize low-emitting energy harvesting methods.

The Section 29 Nonconventional Fuels Tax Credit (Section 29 Tax Credit) was enacted in 1980 to encourage production of nonconventional sources of oil and gas, in response to energy shortages and growing concerns about American dependence on foreign oil.[72] Thirty years later, the success of this supply side incentive is reflected in the shale gas boom.

Today, we face a more pressing need: how to dramatically reduce greenhouse gas emissions from the combustion of fossil fuels. The concept of a "supply-driven" Section 29 Tax Credit could be shifted, then, to incentivize innovations in the way we use fossil fuels. This "use-driven" incentive could encourage more efficient energy utilization (e.g., combined heat and power, fuel cells) and spur investment in zero-carbon energy harvesting research.

RISK: Pollution from Poor Waste Management Practices. Wastes generated during the shale gas extraction process pose a number of risks, including surface and groundwater contamination, air pollution, and the potential for induced seismicity at certain disposal well locations. Multiple risk drivers, and the relative availability of risk mitigation strategies counsel for different approaches to this risk.

Characterizing the Risk. Five to 50% of the millions of gallons of hydraulic fracturing fluid used at each well returns to the surface;[128] this fluid contains small percentages but not insignificant volumes of salts, metals, acids, and in some cases, carcinogenic chemicals.[129] In addition, produced water from the shale formation flows out of the well over its lifetime, along with salts, metals and NORM stripped from the source rock.[128] These fluids may be released into the environment through improper storage, treatment, or disposal methods. While disposal of oil and gas wastewater is nothing new, shale gas production has significantly increased the sector's water and chemical use, and therefore waste volumes.[130]

The risk drivers fall into two categories: the toxicity of the wastewater, and the pathways of exposure. Questions remain about both categories of risk. Not all fracturing fluid or produced water ingredients are publicly disclosed,[131,132] and many chemical constituents have not been studied for their human health or environmental effects.[133] Meanwhile, although some exposure pathways are fairly obvious (e.g., spills from improper handling), others relating to the efficacy of disposal techniques and the long-term integrity of impoundment linings would benefit from more study.

Optimizing Risk Mitigation Strategies. Solutions likewise fall into two categories. In response to public concern about chemical use in hydraulic fracturing, industry began voluntary disclosures of chemicals in 2010.[134] These disclosures, and the state requirements that followed, are limited to the chemicals injected into a well; they do not address the chemical makeup of produced water or compounds resulting from chemical interactions down-hole.[132,135] Fracturing service companies have also designed "green" fracturing fluids of lower toxicity,[136] although it is not clear how prevalent their use is. And in a few states, a company must seek prior approval before using diesel compounds in their fracturing fluid.[137,138] None of these state laws sets forth guidance for granting permission, although two states ban diesel compounds entirely when fracturing into drinking water sources.

To limit exposure pathways, Maryland is undertaking landscape planning, to determine whether shale gas development should be discouraged near drinking water sources and critical habitat.[139] In addition, GE and other companies are developing new techniques for shale gas wastewater treatment.[140]

Regulation. EPA has some jurisdiction over the chemical makeup of shale gas wastewater. Well completion was almost entirely exempted from the Safe Drinking Water Act in 2005; however, EPA may regulate the use of diesel compounds in fracturing fluids.[11,141] EPA issued permitting guidance for diesel compounds in early 2014.[17] Two other federal laws authorize EPA to seek additional information about the chemicals used in well completion; however, thus far the agency has not acted. States have filled this gap with chemical disclosure requirements of their own.[142] The laws vary in the timing and method of disclosure, the level of disclosure required, and the process for protecting confidential business information.

In addition, EPA has authority over two types of shale gas wastewater disposal. First, under the Safe Drinking Water Act, EPA and delegated states approve construction plans[11,143] and set operating requirements for shale gas wastewater disposal wells.[144] Second, EPA regulates wastewater treatment facilities (WWTF) under the Clean Water Act, and may set pretreatment standards for wastewater discharges this year.[16]

All other aspects of oil and gas wastewater management have been delegated to the states. In 1980, Congress enacted the federal hazardous waste law, the Resources Conservation and Recovery Act (RCRA). The law directed EPA to determine if oil and gas exploration and production (E&P) wastes should be regulated as hazardous waste by the agency.[145] Though it acknowledged that E&P waste could be toxic, EPA determined federal regulation was unnecessary; states could regulate the waste as nonhazardous "special waste".[146]

State regulatory programs reflect different approaches to waste management. During well drilling and completion operations, some states still allow wastewater storage in unlined pits;[147] others require lined impoundments[148] or storage tanks.[149,150] Several states require leak detection systems or monitoring.[151,152]

Most states require the closure of waste pits or impoundments after well completion.[153,154] Wastewater may then be spread on roads for ice and dust suppression,[155,156] landfilled or buried in pits,[157,158] sent to WWTF,[159] or injected into underground disposal wells.[160,161] Texas and Pennsylvania encourage wastewater recycling, to reduce the use of fresh water and lower waste volumes.[162,163]

EPA made its "special waste" determination despite capacity concerns about state programs.[146] Consequently, EPA forged a partnership with the Interstate Oil and Gas Compact Commission (IOGCC) to craft guidelines for use in evaluating state waste programs. Since 1999, the State Review of Oil & Natural Gas Environmental Regulations (STRONGER) board has performed these evaluations.[164] If a state requests it, a STRONGER team of state, industry, and NGO representatives will review a state program and make recommendations. Six states have requested a review in the last 10 years.[165] An advisory panel to the Department of Energy has recommended increased federal funding for STRONGER and incentives for states who request review.[93]

Enforcement. Enforcement rates for spills and other shale gas waste pollution incidents are low,[90−92] and the punishment may not be deterring risky behavior.[166]

Against the backdrop of generally low enforcement rates, a few higher-profile cases have highlighted shortcomings in some state waste management programs. In 2011, Pennsylvania incidents revealed that public WWTF were not adequately treating shale gas wastewater before discharging into rivers used for drinking water.[167] In response to an EPA inquiry, Pennsylvania secured a voluntary commitment from industry that it would not send Marcellus shale wastewater to public WWTF.[168] No legal restrictions have been put in place to ensure compliance. In 2013, EPA settled Clean Water Act violations with three commercial WWTF in Pennsylvania, indicating that these facilities may not be adequately treating the waste, either.[169]

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Meanwhile, criminal cases have been brought against waste management companies pouring wastewater down drains or into surface waterways.[170,171] No one knows how prevalent this practice might be; an AP investigation found that Pennsylvania could not account for 1.28 million barrels of wastewater, out of 6 million barrels produced in 2009–2010.[89]

CO/RE Analysis and Paths Forward. The risk of pollution by inadequate wastewater storage, treatment and disposal is fairly clear. Therefore, agencies felt justified in jumping to step three, to regulate the risk. To assist states, EPA helped to establish a collaborative process for evaluating state laws. However, CO/RE suggests collaboration and voluntary efforts may be misplaced in this step. Under the current system, states must ask for STRONGER reviews, and once completed, the states may ignore the results. Instead, EPA could take several actions to drive stronger waste management standards. At the more aggressive end of the spectrum, EPA could revisit its twenty-five year old decision to treat E&P wastes as nonhazardous; however, any resulting rules would have to be approved by Congress.[172] Alternatively, the agency could leave E&P waste regulation to the states, but set minimum solid waste ("Subtitle D") management standards.[173,174] Citizens could directly enforce the standards against industry even if states chose not to adopt the standards.[175] For the cement industry, EPA proposed issuing Subtitle D rules as a backstop only, to go into effect if states did not improve their standards within a certain time period. In the same rulemaking, EPA discussed that it had previously used the Subtitle D framework to craft a waste disposal Memorandum of Understanding (MOU) with the pulp and paper mill industry.[176] An MOU could provide the basis for collaboration around development of cost-effective waste management practices.

Action on regulation should not exclude consideration of other steps. Step two of the CO/RE analysis appears particularly ignored in this issue area. Unlike efforts to measure and reduce methane leakage, waste management has not engendered a productive partnership between agencies and industry that optimizes and deploys risk mitigation strategies. Collaborative efforts might spur development of new waste treatment and disposal technologies, for instance to hear that WWTF are not currently able to cost-effectively treat shale gas water. Agencies then could encourage deployment of these innovations through step three incentive-based regulation, for instance by lowering bonds or reducing impact fees where an operator can document that downstream waste managers employ best practices. Similar incentives might apply to a company that blends a unique tracer in its fracturing fluid, to ensure accountability for its waste. Step two incentives could also reward research into "greener" fracturing fluid additives. Then, incentive-based regulations could reward well operators who reduce the volume and toxicity of their waste through recycling or the use of "green" fracturing fluid formulations.

Step four of CO/RE has also been relatively ignored. As noted, enforcement rates of spills and incidents are low, and the picture of waste management remains murky.[177] Even where states require waste reporting, there appears to be inadequate tracking and enforcement. Absent a stronger grasp on compliance rates and disposal company risk profiles, waste generation and management innovations, smart regulatory responses, and contamination investigations will proceed only slowly, if at all. To fix this, states should improve regulatory tracking of waste. States might consider adopting an "e-manifest" system like the one adopted by the federal government in 2012 for hazardous wastes.[178,179] Congress authorized EPA to set a user fee that underwrites the program;[180] states could do the same. States could redact competitive information but otherwise provide the electronic manifests in a searchable, aggregated online database, to enable tracking of all shale gas waste generated in that state and imported from elsewhere. States could also strengthen chemical disclosure requirements and place quality control conditions on FracFocus, the online chemical registry.

One additional fact frustrating effective waste management enforcement is the large number of small businesses in the waste disposal industry.[181] These companies may have untrained personnel, high turnover rates, and older equipment and trucks that cannot contain corrosive, acidic, or radioactive waste. While traditional enforcement against so large and disparate a group is impracticable, there are at least two ways to cultivate best practices. As a step four enforcement approach, states could rely on the use of tracers to hold well operators directly liable for their wastewater if it is dumped, spilled, or improperly disposed. This would encourage operators to contract with reputable, trained waste disposal companies. Meanwhile, a step two collaborative effort might launch a program to train, register,[182] and audit special waste haulers and disposal facilities. EPA could offer technical assistance to states in this endeavor; third party programs could monitor compliance.[183]

RISK: Methane and Fluid Migration from Wells. A third set of risks relate to methane and fracturing fluid or formation fluid migration through wells that are poorly constructed or poorly maintained. Migration can result in contamination of drinking water[184] or loss of well control.[185]

Characterization of Risk. Industry has identified potential causes for failure of well integrity: tubing and casing leaks; poor cementing practices (improper mud conditioning and displacement); improper cement slurry design or insufficient cement volume; and cement damage.[186] Orphaned wells and transmissive faults can also provide a conduit for movement of methane gas, fracturing liquids, and formation fluids through geologic layers.[187] Several federal agencies are monitoring test wells with natural gas companies, to study well integrity risk drivers,[188] but many agencies lag the larger natural gas companies in their comprehension of this issue.

Optimization of Risk Mitigation Strategies. Driven by safety concerns and the fears of costly well repair operations, industry has optimized innovations in well integrity technology. For instance, advances in anticorrosive tubing,[189] cement chemistry,[190] and computer imaging of subsurface conditions[191] have been developed to improve well integrity. The Center for Sustainable Shale Development has launched a certification program, which would require well integrity best practices from participants.[192] However, in the absence of transparent metrics for best practices, or regulation to ensure technology transfers to smaller companies, the prevalence of industry best practices is unclear.

Regulation. Recognizing that smart regulation could minimize the number of poorly constructed wells and so the risk of fluid migration, in 2010 the Environmental Defense Fund (EDF) and Southwestern Energy began negotiating a set of well integrity standards in a Model Regulatory Framework.[79] The framework incorporates industry best practices in well planning and construction, groundwater testing and monitoring, hydraulic fracturing operations, well maintenance, and effective plugging and abandonment of nonproducing wells.[80]

Ohio apparently relied on the standards when drafting well integrity requirements, and "regulators in Texas and elsewhere have found it useful".[80]

Over the same three year period, some states have updated well integrity[193] and plugging requirements.[194] Several states now require baseline water quality testing[195,196] and monitoring of water quality and quantity in areas near shale gas activity.[151,152]

One potential regulatory gap is coverage of the service companies who often drill and cement the well for an operator. Most state laws require the well owner or operator to apply for drilling permits, and ask for detailed information on drilling activities the operator will not conduct.[197]

Enforcement. As noted in the waste management discussion, enforcement rates of state oil and gas rules tend to be low, and enforcement of underground activities are particularly challenging. Some states have attempted to meet this challenge by crafting presumption of liability schemes. Under this program, operators are found presumptively liable when methane or chemical contamination of groundwater occurs in a certain geographic area and within a certain time period.[198,199] The presumption may be rebutted by predrilling baseline test results.[198,199] Some states have established an investigation process which is triggered when a landowner expresses concern about drinking water contamination.[200−202] However, the state response has so far been inconsistent.[203] Finally, some states are consolidating oversight of well integrity and groundwater protection programs.[204,205]

CO/RE Analysis and Paths Forward. Oil and gas companies have shared well integrity information and technology with each other;[186] however, cross-sector collaboration on this issue is less common. Meanwhile, federal agencies are monitoring so few test wells, it is unclear this work will generate useful generalizations about well integrity. The risk drivers of methane and wastewater migration seem established; however, step two collaboration could help to improve well integrity through the full lifecycle of a hydraulically fractured well. For instance, the Department of Energy could operate a clearinghouse for the sharing of best practices among operators, and facilitate technology transfer to smaller operators. Meanwhile, state and federal agencies could select test wells at random (for instance, every 25th drilling permit application) for lifetime monitoring, to detect prevalence of well failure and identify risk profiles.

At step three, states have incorporated some, but not all industry best practices into their rules. Even where a state may not be comfortable prescribing a specific practice, it might consider reducing permit and impact fees at wells whose operators pledge and document adoption of the practice. Meanwhile, more states and the BLM should require baseline water testing and monitoring, to determine whether and how shale gas activities might affect local water supplies. Finally, well integrity regulation should extend to service companies. These companies should be required to meet certain "certification requirements," and to register with the appropriate agencies.

Enforcement of conditions underground can be difficult. Therefore, agencies will need to be creative in designing compliance mechanisms. For instance, states might require pressure monitors at the wells with readings sent electronically, in real time, to agency computers. An alarm system could indicate when the pressure changes rapidly, indicating a problem. In addition, states should consider conducting a step four analysis to evaluate whether states with a presumption of liability framework have drawn appropriate limits on the presumption. For instance, the presumption in Pennsylvania applies to water wells within 2500 feet of a well, up to a year after completion.[198] This presumption excludes impoundments and migration of methane and chemicals occurring after the first year of well operation. Regulators should evaluate the effects of the presumption and based on the outcome, consider whether to alter its scope. States should also standardize their response to complaints of water contamination. If a water supply should become contaminated, a swift response and long-term replacement of water supplies is critical.

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