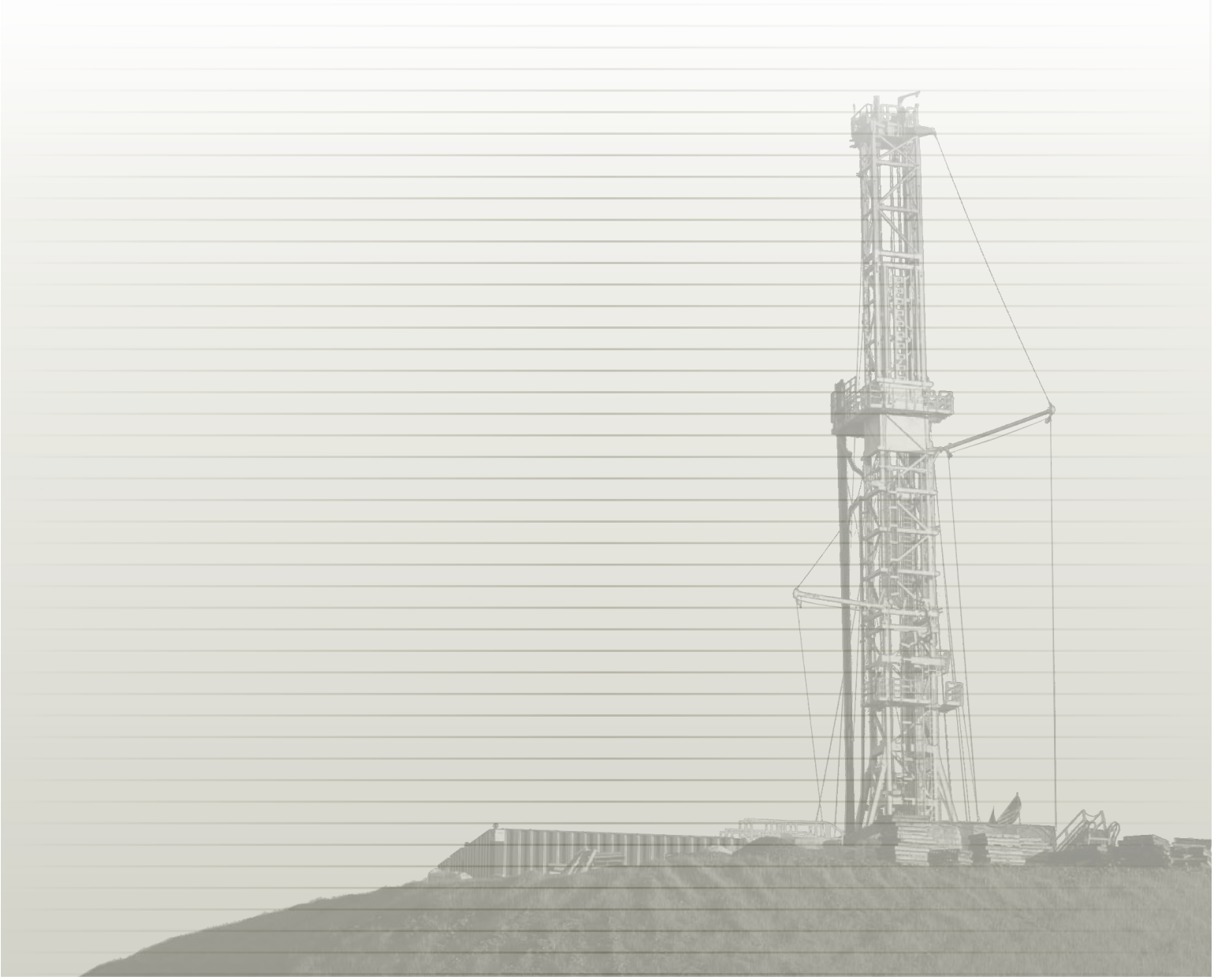
FEBRUARY 2012

Fact-Based Regulation for Environmental Protection in Shale Gas Development



A REPORT BY

energy institute
THE UNIVERSITY OF TEXAS AT AUSTIN

FEBRUARY 2012

Fact-Based Regulation for Environmental Protection in Shale Gas Development

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Preface

The discovery of large reserves of natural gas in shale formations – shale gas – has been a major positive development for the energy picture of the US and the world. Yet a number of controversies over shale gas development have emerged that must be resolved in order for the full potential of this valuable resource to be realized.

The Energy Institute has launched a series of initiatives to help deal with these issues and ensure responsible development of shale gas. This report is from one of these initiatives. It seeks to help policymakers and regulators deal with shale gas issues in a rational manner based on factual information. The report may be found online at the Energy Institute website:

http://energy.utexas.edu/

The Senior Contributors to the report are shown below with their respective areas of contribution:

Matt Eastin	News Coverage and Public Perceptions of Hydraulic Fracturing
Ian Duncan	Environmental Impacts of Shale Gas Development
Hannah Wiseman	Regulation of Shale Gas Development
Hannah Wiseman	State Enforcement of Shale Gas Development Regulation

The investigations continue, and findings will be updated and supplemented as progress is made. Future initiatives are planned to gather more field and laboratory information to improve the scientific basis for development of shale gas resources with adequate control and regulation.

1 Introduction

Natural gas produced from shale formations, commonly referred to as "shale gas", has become increasingly important in the energy supply picture for US and worldwide. Obtaining natural gas from shale units was until recently not considered economically feasible because of low permeability of shales. Economic utilization has been made possible by a pplication and refinement of two previously-developed methods in the oil and gas industry – horizontal drilling and hydraulic fracturing.

The current estimate of the shale gas resource for the continental US is about 862 trillion cubic feet (TCF). This estimate doubled from 2010 to 2011 and is expected to continue to grow with additional resource information. Annual shale gas production in the US increased almost five-fold, from 1.0 to 4.8 trillion cubic feet between 2006 and 2010. The percentage of contribution to the total natural gas supply grew to 23% in 2010; it is expected to increase to 46% by 2035. With these dramatic increases in resource estimates and production rates, shale gas is widely considered a "game changer" in the energy picture for US.

Most would consider this greatly increased availability of natural gas as a highly favorable development for the public interest. Yet a number of controversies have emerged that must be resolved in order for the full benefit of shale gas to be fully realized. The US and the world are in great need of the energy from shale gas resources. In particular, the energy security of the US is greatly enhanced by the full availability of shale gas. At the same time, the resource must be developed with due care for human health and the environment. Meeting these requirements – and addressing controversies – requires carefully-crafted policies and regulations to enhance the public interest in shale gas development.

The Energy Institute at The University of Texas at Austin has funded the initiative leading to this report to promote shale gas policies and regulations that are based on facts – that are well grounded in scientific understanding – rather than claims or perceptions. The initiative is focused on three of the principal shale gas areas of the US – the Barnett shale in Texas, the Haynesville shale in East Texas and Louisiana, and the Marcellus shale in several states in the eastern US.

The overall approach of the initiative was to develop a solid foundation for fact-based regulation by assessing media coverage and public attitudes, reviewing scientific investigations of environmental impacts, and summarizing applicable state regulations and regulatory enforcement. The results are oriented toward energy policy makers in both the public and private sectors – legislators and their staff, state and federal regulators, energy company executives, and non-governmental organizations.

The findings of this initiative have been developed from the professional opinions of a team of energy experts primarily from The University of Texas at Austin. The team was established to incorporate different perspectives and includes representatives from:

- UT Jackson School of Geosciences
- UT Bureau of Economic Geology
- University of Tulsa College of Law (Team member now at Florida State University)
- UT School of Communications
- UT Energy Institute

The team consists of Senior Participants who are faculty members or research scientists conducting state-of-the-art energy research in their respective fields. Staff of the Environmental Defense Fund (EDF) have participated as full members of the project team by assisting with planning the project and providing expert review of the White Papers and project report.

To accomplish the objectives of this initiative, the Senior Participants prepared a set of White Papers covering the major topics relevant to fact-based shale gas regulation:

- News Coverage and Public Perceptions of Hydraulic Fracturing
- Environmental Impacts of Shale Gas Development
- Regulation of Shale Gas Development
- State Enforcement of Shale Gas Development Regulations

The White Papers have been consolidated into the project report. This Summary of Findings provides the highlights of the report for ease of reference by policymakers. The findings are presented for each of the four topical areas and are derived almost entirely from the respective sections. In many cases, almost the exact wording, as well as references to sources, are utilized directly without attribution.

Natural gas resources – and shale gas specifically – are essential to the energy security of the US and the world. Realization of the full benefit of this tremendous energy asset can only come about through resolution of controversies through effective policies and regulations. Fact-based regulation and policies based on sound science are essential for achieving the twin objectives of shale gas resource availability and protection of human health and the environment.

2 Summary of Findings

The findings of this exploration of shale gas regulation are summarized starting with an overview of shale gas followed by a description of media coverage and public perception of its development. The science of shale gas impacts is then reviewed, and the regulatory framework – and the enforcement of regulations – are described. Finally, the compiled results of the investigation are interpreted for future fact-based regulation of shale gas development.

Shale gas is considered an unconventional gas resource because in conventional exploration and development it is understood that natural gas originates in shale as a "source rock" but that it must migrate into porous and permeable formations (termed "reservoirs"), such as sandstones, in order to be produced economically. Shale gas production involves going directly to the source rock to access the resource. Such production from shale units was not considered economically feasible before application and refinement of horizontal drilling and hydraulic fracturing.

Shale units capable of producing natural gas in large quantities are found in five regions of the continental US. They are shown below with the shale plays and percent of US resources:

- Northeast: primarily the Marcellus (63%)
- Gulf Coast: Haynesville, Eagle Ford (13%)
- Southwest: Barnett and Barnett-Woodford (10%)
- Mid-Continent: Fayetteville, Woodford (8%)
- Rocky Mountain: primarily Mancos and Lewis (6%)

The use of hydraulic fracturing to increase production from conventional oil and gas wells grew rapidly starting in the late 1940s and continues to be used routinely for reservoir stimulation. Since its initiation, hydraulic fracturing has been used to stimulate approximately a million oil and gas wells. Improvements in horizontal drilling technologies, such as downhole drilling motors and telemetry equipment, led to its increased application in conventional drilling starting in the early 1980s. A partnership between agencies of the US government, a gas industry consortium, and private operators beginning in the 1970s led to the development of horizontal drilling and multi-stage hydraulic fracturing, which were critical to economic production of shale

gas. The development efforts of Mitchell Energy Corporation in the Barnett shale in Texas during the 1980s and 1990s were critical in the commercial success of shale gas production.

Shale gas has become embroiled in controversy over alleged impacts on public health and the environment. Some segments of the public have become deeply suspicious of the veracity and motives of gas companies. These suspicions were intensified by the natural gas producers and gas field service companies initially refusing to disclose the chemical makeup of fluids used to enhance hydraulic fracturing. Many outside observers have concluded that it is "likely", "highly likely" or "definitively proven" that shale gas extraction is resulting in widespread contamination of groundwater in the US. For example[1], one study of the impacts of shale gas exploitation in the US asserted that "there is considerable anecdotal evidence from the US that contamination of both ground and surface water has occurred in a range of cases". In another example, a university professor stated in a written submission to the EPA that "Shale gas development clearly has the potential to contaminate surficial groundwater with methane, as shown by the large number of incidences of explosions and contaminated wells in Pennsylvania, Wyoming, and Ohio in recent years." and that "… shale gas development has clearly contaminated groundwater and drinking water wells with methane…".

The response from the gas industry and its supporters has generally been denial – not only that any such problems exist but also that if they did exist they are not real risks. For example[2], one industry website denied that the migration of fracturing fluid underground is among the "environmental and public health risks" of hydraulic fracturing and shale development. In another example, a university professor who is a shale gas proponent told a Congressional Committee that "the hydraulic fracturing process is safe, already well regulated by the various States" and that "the hysterical outcry over this process is completely unjustified".

The debate between protagonists and antagonists of shale gas development has in some cases become strident and acrimonious. Negative perceptions and political consequences have led to

[1] The examples cited are from the report section on Environmental Impacts of Shale Gas Development.

[2] The examples cited are from the report section on Environmental Impacts of Shale Gas Development.

the prohibition of shale gas development in a number of instances, at least temporarily. Realization on the part of all stakeholders of the large national energy security and other benefits of shale gas resource – when developed with adequate protection of public health and the environment – may provide "common cause" for seeking solutions.

The most rational path forward is to develop fact-based regulations of shale gas development based on what is currently known about the issues and, at the same time, continue research where needed for information to support controls in the future. Additional or improved controls must not only respond to the issues of controversy, but also address the full scope of shale gas development. Priorities must be set on the most important issues as well as on pu blic perceptions. The path ahead must take advantage of the substantial body of policies and regulations already in place for conventional oil and gas operations. Enforcement of current and future regulations must also be ensured to meet the twin objectives of protection of environment and other resources and gaining public acceptance and support.

2.1 Media Coverage and Public Perception

All six shale gas areas were assessed for media coverage. Public perception was determined for the Barnett Shale area.

2.1.1 Media Coverage

Media coverage of hydraulic fracturing, a critical and distinctive component of shale gas development, was assessed for tonality (negative or positive) and reference to scientific research. The assessment covered the period from June 2010 to June 2011 and included three areas:

- Barnett shale area (Dallas, Tarrant, and Denton counties, Texas)
- Haynesville shale area (Shreveport, Louisiana)
- Marcellus shale area (six states)

The six Marcellus locations were Pennsylvania (Pittsburgh), New York (Buffalo), West Virginia (Charleston), Maryland (Hagerstown), Ohio (Cleveland), and Virginia (Roanoke). Four types of media – newspapers (national and metropolitan), television (national and local), radio (national

and local), and online (Google News) – were included using searches for keywords for hydraulic fracturing in 14 groups as follows:

Well Blowout	Pipeline Leaks
Water Well Contamination	Regulatory Enforcement
Frac Fluid (and Frack Fluid)	Local Government Response
Surface Spills or Accidental Release	Public Interest and Protest Groups
Flow-Back Water	Barnett Shale Groups
Water Disposal Wells	Wyoming Groups
Atmospheric Emissions and Air Quality	Marcellus Group

Media coverage of shale gas development was assessed in the Marcellus, Haynesville, and Barnett shale areas. The analysis of the tonality of articles and broadcasts included 13 newspapers (three national and 10 metropolitan), 26 br oadcast media (seven national and 18 metropolitan television stations and one national radio station), and one online news source.

For the nation as a whole, the attitudes were found to be uniformly about two-thirds negative.

	Negative	Neutral	Positive
National Newspapers (3)	64%	25%	12%
Metropolitan Newspapers (10)	65%	23%	12%
National Television & Radio (7)	64%	19%	18%
Metropolitan Television (18)	70%	27%	3%
Online News (1)	63%	30%	7%

The local media coverage for each of the shale areas shows similarity to the national results for the Barnett and Marcellus shale areas; the Haynesville area may be anomalous because only one newspaper and one television source were available.

	Negative	Neutral	Positive
		Barnett Shale Area	
Newspapers (3)	79%	6%	16%
Television (6)	70%	30%	0%
		Marcellus Shale Area	
Newspapers (6)	67%	25%	8%
Television (11)	74%	20%	6%
		Haynesville Shale Area	
Newspapers (1)	8%	46%	46%
Television (1)	0%	100%	0%

With respect to reference to scientific research, the search found that few articles referenced research on the topic of hydraulic fracturing:

	Percent Referencing Scientific Research
Newspaper Articles	18%
Television Reports	25%
Radio Coverage	15%
Online Coverage	33%

2.1.2 Public Perception and Knowledge

Public perception of hydraulic fracturing was assessed specifically in the Barnett shale area utilizing an online survey method that included 75 questions in six categories:

Thoughts about hydraulic fracturing	Perceptions about hydraulic fracturing
Knowledge of hydraulic fracturing	Behaviors
Media use	Demographics

The area included was expanded to 26 counties in Texas, and the survey included almost 1500 respondents. The results of the survey indicate a generally positive attitude toward hydraulic fracturing, with more favorable responses for the following descriptors: good for the economy, important for US energy security useful, important, effective, valuable, and productive. Attitudes were neutral to slightly positive as indicated by response to several descriptors for hydraulic fracturing: importance for US energy security, safety, beneficial or good, wise, and helpful. There was a more negative attitude, however, about environmental concerns. Hydraulic fracturing was felt to be bad for the environment by about 40% of the respondents. Another 44% were neutral and only 16% were positive.

With respect to knowledge of hydraulic fracturing, many respondents were found to have some general knowledge about the process of hydraulic fracturing, but they tend to lack an understanding of regulation and the cost-benefit relationship of production:

- Most respondents overestimate the level of hydraulic fracturing regulation; for example, 71% were not aware that the Railroad Commission does not regulate how close a gas well can be drilled to a residential property.

- Many respondents (76%) overestimate annual water consumption for shale gas usage and underestimate (75%) the amount of electricity generated from natural gas.
- Most generally understand the process of fracturing and gas development surrounding the fracturing of wells, but the scope and technical aspects of fracturing are less well understood. For example, 49% were unaware of proppants, and 42% overestimated scientific evidence surrounding the issue of hydraulic fracturing and water contamination.
- Knowledge of policy issues related to groundwater contamination, such as the disclosure of chemicals used in fracturing and active groups affiliated with groundwater issues, was high.
- Knowledge of the occurrence of well blowouts in hydraulic fracturing was high (73%), as well as the impact of blowouts comparison to surface spills (72%). And 54% understand the frequency that blowouts have occurred in the Barnett shale.

Hydraulic fracturing knowledge was also assessed for the following five areas:

- Awareness of Hydraulic Fracturing. 50% of the respondents consider themselves to be somewhat aware or very aware hydraulic fracturing. The other 50% were not very aware or were not aware at all.
- Concern about Water Quality. 35% indicated they were very concerned, and 40% were somewhat concerned. 24% were not very concerned or not at all concerned.
- Disclosure of Chemicals Used in Hydraulic Fracturing. Regarding whether state and national officials are doing enough to require disclosure, 12% thought that the officials are doing everything they should, and 32% indicated that officials were doing some of what they should. 47% indicated not as much as should be done was being done. 9% thought that nothing at all was being done.
- Message to Politicians. When asked about relative priorities of energy production on the one hand and public health and the environment on the other, 67% indicated higher priority on public health and the environment.
- America's Future Energy Production. When asked to prioritize between meeting energy needs (and override concerns about water shortages and pollution) on the one hand and

focusing on energy sources that require the least water and minimal water pollution impacts on the other hand, 86% placed higher priority on second choice.

The survey also included an assessment of the degree of willingness to get involved in community efforts, such as organizing, protesting, calling legislators, and petitioning. The results indicate that people are either undecided or ambivalent, or they sense two equal points of view and aren't sure which one to accept. It also appears that respondents sense that it is not desirable to get involved – they are mostly unwilling to participate in any events in support of or against hydraulic fracturing. This could be related to their ambiguous attitudes.

2.2 Environmental Impacts of Shale Gas Development

Shale gas development, as with all types of resource utilization, should take place with adequate protective measures for human health and the environment. Although many of the shale gas controversies have arisen over concerns about adverse impacts of hydraulic fracturing, all phases of shale gas operations and their potential impact should be addressed. The various phases of the shale gas development life cycle and their associated issues have been organized for the assessment as follows:

- Drill Pad Construction and Operation
- Hydraulic Fracturing and Flowback Water Management
- Groundwater Contamination
- Blowouts and House Explosions
- Water Consumption and Supply
- Spill Management and Surface Water Protection
- Atmospheric Emissions
- Health Effects

These shale gas phases and their impacts have been assessed based on a review of scientific and other literature on shale gas development.

2.2.1 Drill Pad Construction and Operation

During the construction phase for a well pad and associated infrastructure such as unimproved or gravel roads, the quality of surface water resources may be impacted by r unoff, particularly during storm events. Soil erosion and transport of sediment into streams and other water bodies must be managed not only to protect water quality but also to prevent damage to ecological habitats. During both construction and operation, protection must also be provided against leaks and spills of oil and grease, VOCs, and other contaminants.

Regulations under the Clean Water Act require Storm Water Management Plan (SWMPs) to protect water quality during high precipitation events. The requirements of an SWMP may not highly specific but instead call for Best Management Practices (BMPs), which include erosion and sediment control measures such as seeding, filter fences, terraces, check dams, and straw bales. Studies of sediment yields from well pad sites during storm events indicate a comparable

yield to typical construction sites – from 15 to 40 tons per hectare per year. The US DOE National Energy Technology Laboratory (NETL) sponsors a wide range of research into water quality and ecological impacts and mitigative measures for drill pads and access roads, including improved road designs, impacts on sensitive birds, and impacts on wildlife in streams (particularly large invertebrates).

Shale gas development will affect forests and ecological habitat at a large scale as well. Studies of development in the Marcellus shale area indicate that two thirds of well pads will be constructed in forest clearings, resulting in the clearing of 34,000 to 83,000 acres for pads and an additional 80,000 to 200,000 acres of habitat impacts from pads and associated road infrastructure.

2.2.2 Hydraulic Fracturing and Groundwater Contamination

Of all the issues that have arisen over shale gas development, hydraulic fracturing and its claimed effects on groundwater are without doubt the most contentious. The term has become such a lightning rod that it is equated in the eyes of many with the entire cycle of shale gas operations – from drilling to fracturing, completion, and production. Many allegations have been made about contamination of groundwater caused by hydraulic fracturing, with particular emphasis on impacts on water wells. A contributing factor to the level of controversy may well be the location of portions of shale gas plays in proximity to urban centers and other highly densely populated areas, resulting in closer contact with the general public than in previous in oil and gas operations.

The concerns over hydraulic fracturing and related activities have a number of dimensions, but they can be summed up with a few relevant questions:

1. Does the composition of additives to the fracturing fluid pose extraordinary risk drinking water?
2. Does fracturing fluid escape from the shale formation being treated and migrate to aquifers?
3. Are claims of hydraulic fracturing impacts on water wells valid?
4. Does the flowback and produced water after fracturing have a negative impact?
5. Does hydraulic fracturing lead to well blowouts and house explosions?

The last two questions are addressed in subsequent sections of this Summary of Findings.

Fracturing Fluid Additives

The overall composition of the fluid used for hydraulic fracturing varies among companies and the properties of the shale being treated. In general the fluid is about 90% water, 9.5% proppant particles, and 0.5% chemical entities (the latter percentage is variable but is less than 1%). The additives have a number of purposes, including reducing friction (as the fluid is injected), biocide (to prevent bacterial growth), scale inhibition (to prevent mineral precipitation), corrosion inhibition, clay stabilization (to prevent swelling of expandable clay minerals), gelling agent (to support proppants), surfactant (to promote fracturing), and cleaners. Estimates of the actual chemicals utilized range as high as 2500 service company products containing 750 chemical compounds.

The detailed composition of the additives has been controversial because until recently the companies that manufacture fracturing fluid components have insisted that the exact composition was proprietary. But over the last two years, voluntary disclosures and state-based disclosure laws (e.g., Texas) have resulted in increased openness on the details of the composition of the chemical components of fracturing fluids. In spite of the much broader disclosure of the ingredients of the additives, there is not yet a clear understanding of what are the key chemicals of concern for environmental toxicity or their chemical concentration in the injected fluid.

The Waxman Committee Report[3] is the most comprehensive publicly available study of the chemical makeup of additives used in hydraulic fracturing fluids. Many of the chemicals listed are no longer in use. The report indicates that from 2005 to 2009, some 95 products containing 13 different carcinogens were utilized in hydraulic fracturing. Four compounds – 2-BE (a surfactant), naphthalene, benzene, and acrylamide (or polyacrylamide) – were singled out in this report for special emphasis. As context for the analysis of the impact of these compounds, it should be noted that all four are widely used in the manufacture and use of many commercial products and other applications.

[3] See Section 2 of the full report for the Waxman Report reference.

2-BE (noted in the report for destruction of red blood cells and dangerous to the spleen, liver, and bone marrow) is widely used in many commercial products, such as solvents, paints, polishes, pesticides, household cleaners, and brake fluids. As a result of the production and use of 2-BE, it is now widely dispersed in a natural environment. In Canada alone, for example, 6100 tonnes of 2-BE were sold in 1996 as part of consumer products or for commercial uses. 2-BE is highly biodegradable, and in any case it is being replaced in hydraulic fracturing with a new product having low toxicity and with properties requiring use of a much lower volume of product.

Benzene (a known human carcinogen) and naphthalene (a probable human carcinogen) are also widely distributed in modern society. Naphthalene, for example, is a major component of mothballs and toilet bowl deodorizers. It is relatively biodegradable (half-life of a few weeks in sediment). Exposures to benzene take place through use of consumer products and in a number of workplace environments, as well as from fumes from gasoline, glues, solvents, and some paints. Cigarette smoking and secondhand smoke are significant sources of benzene exposure, accounting for about 50% of benzene exposure in the general population of the US.

PAM (polyacrylamide, which is confused with acrylamide in the Waxman report) is widely used as a consumer product – such as non-stick spray or frying pans, biomedical applications, cosmetics, and textiles – as well as other applications such as flocculants, thickening agents, and soil conditioners. Although some risk assessment research has been done for several environmental applications of PAM, it has generally been assumed that PAM is safe.

Although the release of more of these chemicals, which are used for many applications, into the environment by hydraulic fracturing is not necessarily totally acceptable, their use should be evaluated in the framework of other broad uses and environmental releases as well as the depth of release, which is typically several thousand feet below the surface.

Migration of Fracture Fluids to Aquifers

Closely related to the concerns about the chemicals in hydraulic fracturing fluid additives are allegations that the fluids are not contained in the shale being fractured but instead escape and cause groundwater contamination. The route of escape may be through propagation of induced

fractures out of the target zone and into aquifers, intersection of induced fractures with natural fracture zones that lead to aquifers, through abandoned and improperly plugged oil and gas wells, or upward in the well bore through the annulus between the borehole and the casing.

However, there is at present little or no evidence of groundwater contamination from hydraulic fracturing of shales at normal depths[4]. No evidence of chemicals from hydraulic fracturing fluid has been found in aquifers as a result of fracturing operations. As noted in a subsequent section, it appears that the risk of such chemical additives is greater from surface spills of undiluted chemicals than from actual fracturing activities.

Although claims have been made that "out-of-zone" fracture propagation or intersection with natural fractures, could occur, this study found no instances where either of these has actually taken place. In the long term after fracturing is completed, the fluid flow is toward (not away from) the well as gas enters the well bore during production. Some allegations indicate a relatively small risk to water supplies from individual well fracturing operations, but that a large number of wells (in the Marcellus shale) has a higher likelihood of negative impacts. However, the evidence for this risk is not clearly defined.

Much of the concern is for migration of natural gas through unplugged abandoned oil and gas wells is for natural gas and the risk of house explosions and methane contamination of water wells, which are addressed in subsequent sections. The issue of well integrity and potential leakage upward around the well casing is connected to well blowouts and water well impacts by natural gas, which are also addressed below.

Impacts of Hydraulic Fracturing on Water Wells

Many allegations have been made by residents in shale gas areas of impacts on water wells by shale gas development activities. Claims of water well impacts have been among the most prominent of the shale controversies. The majority of the claims involve methane, chemical constituents (iron, manganese, etc.) and physical properties such as color, turbidity, and odor.

[4] Apparently in some cases, such as the Pavilion area, Wyoming, fracturing has been performed at depths shallower than normal for shale gas wells, which are typically more than 2,000 or 3,000 feet deep.

These properties and constituents in many cases were present in water wells before shale gas development began, but often there is insufficient baseline (pre-drilling) sampling or monitoring to establish the impacts of drilling, fracturing, and other operations.

Iron and manganese are common naturally-occurring constituents in groundwater that are higher in concentration in some aquifers than others. Particularly in areas underlain by gas-producing shales, methane migrates out of the shales under natural conditions and moves upward through overlying formations, including water-bearing strata (aquifers). Such naturally-occurring methane in water wells has been a problem in shale gas areas for many years or decades before shale gas drilling began.

It appears that many of the water quality changes observed in water wells in a similar time frame as shale gas operations may be due to mobilization of constituents that were already present in the wells by energy (vibrations and pressure pulses) put into the ground during drilling and other operations rather than by hydraulic fracturing fluids or leakage from the well casing. As the vibrations and pressure changes disturb the wells, accumulated particles of iron and manganese oxides, as well as other materials on the casing wall and well bottom, may become agitated into suspension causing changes in color (red, orange or gold), increasing turbidity, and release of odors.

None of the water well claims involve hydraulic fracturing fluid additives, and none of these constituents has been found by chemical testing of water wells. The finding of acrylonitrile in a water well in West Virginia resulted in major concerns about its potential source in hydraulic fracturing fluid. However, no evidence has been found that this compound has ever been used in fracturing fluid additives.

The greatest potential for impacts from a shale gas well appears to be from failure of the well integrity, with leakage into an aquifer of fluids that flow upward in the annulus between the casing and the borehole. Well integrity issues resulting in leakage can be divided into two categories. In annular flow, fluids move up the well bore, traveling up the interface between the rock formation and cement or between the cement and the casing. Leak flow is flow in a radial direction out of the well and into the formation. In general, a loss of well integrity and associated

leakage has been the greatest concern for natural gas – leading to home explosions as described in a subsequent section.

2.2.3 Flowback and Produced Water Management

After hydraulic fracturing has been accomplished in a shale gas well, the fluid pressure is relieved and a portion of the injected fluid returns to the well bore as "flowback" water, which is brought to the surface for treatment, recycling, and/or disposal. The fluid withdrawn from the well actually consists of a mixture of the flowback water and saline water from the shale formation, which is referred to as" produced" water. As withdrawal proceeds, the fluid becomes more saline as the relative contribution of produced water to the flow increases. The point in time when produced water dominates the flow has been a subject of controversy.

The amount of injected fluid returned as flowback ranges widely – from 20% to 80% – due to factors that are not well understood. The ratio of ultimate water production after fracturing to the volume of fracturing fluid injected varies widely in the different shale areas – Barnett (3.1), Haynesville (0.9), Fayetteville (0.25), and Marcellus (0.15). The return of hydraulic fracturing fluid is important because as recycling increases in the industry a higher rate of return reduces the water requirements of shale gas production. Greater emphasis is being placed on recycling and reuse not only to reduce water requirements but also to reduce the volume of flowback wastewater that must be managed.

Management of the combined flowback and produced water streams has become a major part of the shale gas controversy, both from the standpoint of uncontrolled releases and the treatment, recycling, and discharge of the fluid as a wastewater stream. Disposal of the flowback water has historically been primarily by permitted injection wells in the Barnett and Haynesville shale areas and by discharge to publicly-owned treatment works in the Marcellus shale area.

Flowback water contains some or all of the following: sand and silt particles (from the shale or returned proppants), clay particles that remain in suspension, oil and grease from drilling operations, organic compounds from the hydraulic fracturing fluids and the producing shale, and total dissolved solids (TDS) from the shale. This composition reflects the mixed origin of the fluids from hydraulic fracturing and produced shale water. The average TDS of flowback water

has a considerable range for the different shale plays – 13,000 ppm for the Fayetteville, 80,000 ppm for the Barnett, and 120,000 ppm for the Marcellus. But there is also considerable variation in the TDS content in wells within each shale area. For example, one study of the Marcellus shale found a range of 1850 to 345,000 and mg/L.

Of the chemicals found in fluids related to shale gas development, the one that appears to be of greatest concern is arsenic. Although arsenic is not uncommon in domestic water wells where no hydraulic fracturing has taken place, it has become a source of strong allegations in Texas and Pennsylvania. Concerns over arsenic and other contaminants and flowback water have resulted in demands for increased regulation.

Although there has been considerable controversy over hydraulic fracturing fluid additives and their potential impact on water supplies, the potential risk of naturally-occurring contaminants like arsenic in flowback and produced water is also a major concern. Similar concern about risk may be associated with organic chemicals in flowback and produced water that may be present in injected hydraulic fracturing fluids or in the formation water of the shale.

2.2.4 Blowouts and House Explosions

Unplanned releases of natural gas in the subsurface during drilling may result in a blowout of the well or migration of gas below the surface to nearby houses, where the gas may accumulate in concentrations high enough to cause an explosion.

<u>Blowouts</u>

Blowouts are uncontrolled fluid releases that occur rarely during the drilling, completion, or production of oil and gas wells. They typically happen when unexpectedly high pressures are encountered in the subsurface or because of failure of valves or other mechanical devices. Blowouts may take place at the wellhead or elsewhere at the surface, or they may involve movement away from the well in the subsurface. High pressures may be encountered in natural gas in the subsurface or may be artificially induced in the well bore during hydraulic fracturing.

Many blowouts happen as a result of the failure of the integrity of the casing or the cementing of the casing such that high-pressure fluids escape up well bore and flow into subsurface

formations. Blowout preventers (BOPs) are used to automatically shut down fluid flow in the well bores when high pressures ("kicks") are encountered, but like other mechanical devices, they been known to fail, although infrequently.

Blowouts are apparently the most common of all well control problems, and they appear to be under-reported. Data are not available on the frequency of blowouts for onshore oil and gas wells, but data from offshore wells indicate that the frequency is between 1 and 10 per 10,000 wells drilled for wells that have not yet had a BOP installed. The frequency depends on whether the well is being drilled or completed and whether the blowout is at the surface or in the subsurface.

Surface blowouts at the wellhead are primarily a safety hazard to workers and may also result in escape of drilling fluid or formation water to nearby surface water sources. Subsurface blowouts may pose both safety hazards and environmental risks. The potential environmental consequences of a blowout depend mostly on three factors: 1) the timing of the blowout relative to well activities (which determines the nature of the released fluid such as natural gas or pressurized fracturing fluid); 2) occurrence of the escape of containments through the surface casing or deep in a well; and 3) the risk receptors, such as freshwater aquifers or water wells, that are impacted. A major problem in these events is the limited ability to discern what is happening in the subsurface. For example, when a pressure kick causes a BOP to prevent flow from reaching the surface, the fluid may exploit weaknesses in the casing and cement below the BOP and escape into the surrounding formations (or aquifers).

Blowouts due to high gas pressure or mechanical failures happen in both conventional and shale gas development. Shale gas wells have the incremental risk of potential failures caused by the high pressures of fracturing fluid during hydraulic fracturing operations. Underground blowouts occur in both wells that had been or about to be hydraulically fractured. For example, in the Barnett shale, the Railroad Commission of Texas determined that two of 12 blowouts were underground, but publicly available information is insufficient to evaluate the causes or consequences of the blowouts.

An example of the environmental consequences of an underground blowout (related to conventional rather than shale gas drilling) has been reported in Louisiana, in which pressure changes in the Wilcox aquifer caused a number of water wells around the blowout will to start spouting water. And two craters also formed around two abandoned wells near the drill site.

In another incident in Ohio, again not involving shale gas drilling, high-pressure natural gas was encountered and moved up the well bore and invaded shallow rock formations. Within a few days gas bubbling was observed in water wells and surface water, and the floor of a basement in a house was uplifted several inches. Over 50 families were evacuated from the area. The well was brought under control and capped a week later.

Although the Louisiana and Ohio examples did not involve shale gas operations, they are illustrative of the types of blowout impacts that can occur when high pressure natural gas is encountered. In general, issues of blowouts – whether from high pressure natural gas or from high pressure hydraulic fracturing – may be addressed most effectively through proper well construction and ensuring well integrity.

House Explosions

Claims of impacts on water wells as a result of shale gas drilling have included methane as well as chemical contaminants as described in Section 4.2. Such observations are in most cases the result of naturally-occurring methane migration into aquifers and wells before shale gas development began. In addition to impacts on water quality in wells, claims have also been made of home and wellhouse explosions caused by migration of natural gas from shale gas wells. In one well-known case in Ohio, a house exploded soon after a nearby hydraulically fractured well was drilled. After much investigation by the regulatory agency and a private geological engineering consulting firm, followed by study of the case by a distinguished review committee, it was concluded that methane may have migrated to the house along shallow horizontal fractures or bedding planes. On the other hand, it was observed that the groundwater have very low levels of dissolved methane.

Other cases of methane explosions in homes and wellhouses have been investigated in Colorado, Pennsylvania, and Texas. In some of these cases, the explosions were found caused by gas

migration from hydraulically fractured wells. In general, if natural gas migrates away from a shale gas or conventional gas well, it is because well integrity has been compromised such as through failure of the surface casing or cement job.

2.2.5 Water Requirements and Supply

Water consumption, particularly for hydraulic fracturing, is one of the most contentious issues for shale gas development. The drilling and fracturing of shale gas wells requires significant quantities of water for drilling mud, extraction and processing of proppant sands, testing natural gas transportation pipelines, gas processing plants, and other uses.

Although many of these requirements apply to conventional natural gas production as well as shale gas specifically, consumption is greater for hydraulic fracturing than for other uses. The water required to hydraulically fracture a single well has varied considerably as hydraulic fracturing of shale gas has become dominated by more complex, multi-staged horizontal wells. The average quantity of water used for a shale gas well varies somewhat by the shale gas area: Barnett (4.0 million gallons), Fayetteville (4.9 MG), Marcellus and Haynesville (5.6 MG), and Eagle Ford (6.1 MG).

Several metrics have been used in an attempt to quantify the significance of water used in shale production, but the most popular has been the energy water intensity (volume of water used per unit of energy produced). There appears to be a consensus among shale gas researchers that the water intensity of shale gas is relatively small compared to other types of fuels. The energy water intensity for the Barnett, Marcellus, and Haynesville shale plays has been estimated at 1.32, 0.95, and 0.84 gallons per million BTU, respectively.

The US EPA has estimated that if 35,000 wells are hydraulically fractured annually in the US, the amount of water consumed would be equivalent to that used by 5 million people. Pennsylvania's annual total water consumption is approximately 3.6 trillion gallons, of which the shale gas industry withdraws about 0.19% for hydraulic fracturing.

Water for shale gas wells may be obtained from surface water (rivers, lakes, ponds), groundwater aquifers, municipal supplies, reused wastewater from industry or water treatment plants, and

recycling water from earlier fracturing operations. The primary concerns – and sources of controversy – are that the withdrawals will result in reduced stream flow or will deplete groundwater aquifers. Water impacts vary considerably by locations of withdrawals, and the seasonal timing of the withdrawal can be a critical difference between high impact and no impact on other users. The most reasonable approach to assessing water usage is to evaluate the impact it has on the local community and the local environment both in the short- and long-term. An important distinction among water sources is whether the water usage is sustainable (renewable). For example, surface-water usage is likely to be more sustainable than groundwater usage.

The sources for water used for hydraulic fracturing are not well documented in most states because the patchwork of agencies responsible for various water sources do not closely monitor withdrawals or consumption. Water sources and withdrawals differ significantly for the Barnett, Haynesville, Marcellus, Fayetteville, and Eagle Ford shale areas.

2.2.6 Spill Management and Surface Water Protection

Leaks and spills associated with shale gas development may occur at the drill pad or during transport of chemicals and waste materials. Sources at the wellsite include the drill rig and other operating equipment, storage tanks, impoundments or pits, and leaks or blowouts at the wellhead. Leaks or spills may also occur during transportation (by truck or pipeline) of materials and wastes to and from the well pad. The primary risk of uncontrolled releases is generally to surface water and groundwater resources.

On-site and off-site releases may occur because of accidents, inadequate facilities management or staff training, or illicit dumping. Released materials include fuels, drilling mud and cuttings, and chemicals (particularly for hydraulic fracturing). Hydraulic fracturing chemicals in concentrated form (before mixing) at the surface present a more significant risk above ground than as a result of injection in the deep subsurface.

Wastewater from flowback and produced water is typically temporarily stored in on-site impoundments before removal by trucks or pipeline for reuse, treatment, or disposal. These impoundments may be another source of leaks or spills. Lining of pits for flowback water depends on company policies and regulatory requirements, which vary from state to state.

Because liners may leak, releases to the subsurface may still occur, resulting in calls to discontinue the use of pits in favor of closed-loop steel tanks and piping systems.

Three characteristics of a spill generally determine the severity of its consequences – volume, degree of containment, and toxicity of the fluid. Depending on toxicity, smaller releases generally have lower impact than larger spills. Effective containment is key to minimizing the impacts on human health and the environment when a spill occurs. The more toxic the release is, the higher the risk if containment is not effective to prevent migration into exposure pathways that are linked through surface water or groundwater to humans, animals, or other receptors.

An important aspect of spill management is to provide secondary containment for areas of fuel and fracturing fluid chemicals storage, loading and unloading areas, and other key operational areas. Such containment prevents a spill from reaching surface water or groundwater through the use of liners or other barriers.

Little information is available on the short- or long-term consequences of surface spills. Regulatory reports on spill investigations do not necessarily include information that would allow evaluation of environmental damage or the effectiveness of remedial responses. Data are also not readily available from regulatory agencies on the frequency of spills and other releases. One experiment in West Virginia involved an intentional release of about 300,000 gallons of flowback water in a mixed hardwood forest followed by observation of the effects on trees and other vegetation. Ground vegetation was found to suffer extensive damage very quickly followed by premature leaf drop from trees in about 10 days. Over two years the mortality rate for the trees was high – greater than 50% of one species. Available data indicate that the high salinity of the flowback water was responsible for the underbrush and tree mortality.

Advance planning to be prepared to respond to a spill is essential to minimize impacts. The most effective way to reduce risk of spills is to avoid the use of toxic chemicals through substitution of non-toxic substances were possible or by arranging for just-in-time delivery to reduce risks of on-site storage. Many states require Spill Prevention Control and Contingency (SPCC) plans at well pad sites, which specifies the best practices to be used in the event of a release. Spill management and remediation should be accomplished based on contingency plans that are

prepared in advance and are developed jointly with regulatory agencies and emergency responders. Rapid communication of that nature, volume, and toxicity of a spill is essential to effective emergency response.

2.2.7 Atmospheric Emissions

Air emissions from shale gas operations occur at the drill site during drilling and fracturing and at ancillary off-site facilities such as pipelines, natural gas compressors. The onsite emissions include dust, diesel fumes, fine particulate matter (PM 2.5), and methane. Air emissions have become a major component of the shale gas controversies.

A principal concern is for shale gas emissions is related to the volatile organic carbon (VOC) compounds. Depending on the composition of the gas produced from the shale, VOCs are typically rich in the BTEX (benzene, toluene, ethylene, xylene) compounds. However, the role of VOCs as smog precursors – they combine with NOx in the presence of sunlight to form smog – is the main source of concern with these compounds. Ozone, a primary constituent of smog, and NOx are two of the five "criteria pollutants" of the Clean Air Act (CAA). The Fort Worth area in the Barnett shale play has been designated "non-attainment" for ozone under the CAA, which means that the established standard is not met for ozone concentration in the atmosphere. The role of VOCs in forming smog and their contribution to the elevated levels of ozone is the reason for the focus on VOC emissions from shale gas activities.

However, the contribution of shale gas activities to ozone levels is highly controversial. For example, investigations in the Fort Worth area have found that most VOCs are not associated with natural gas production or transport. Allegations that VOC and NOx emissions from natural gas production from Barnett shale activities play a significant role in ozone formation have been strongly contested. Records of the Texas Commission on Environmental Quality (TCEQ) monitoring program since 2000 actually show overall decreases in the annual average concentration of benzene, one of the VOCs, during the period of early shale gas development in the Fort Worth area.

Public concern over air quality and the need for more precise information led to more focused emissions studies sponsored by local governments or private foundations. The first – and most

controversial – of these studies was at DISH, Texas, where elevated levels of benzene, xylene, and naphthalene were found from a set of 24 samples and four residences. Another study in a very active area of shale gas production located about seven or eight miles from DISH found that shale gas was responsible for less than half of the VOCs (43%) in the atmosphere, with motor vehicle emissions contributing most of the rest (45%). Modeling studies indicate that 70 to 80% of benzene is from fugitive emissions of natural gas, but that other VOC constituents are from motor vehicle emissions.

In portions of Western states such as Wyoming, air emissions from oil and gas activities are the largest source of VOCs and related high ozone levels. In Sublette County, Wyoming, for example, ozone levels in the winter routinely exceed the EPA 8-hour standard, resulting in air quality that is sometimes worse than in Los Angeles.

Allegations that the emission of VOC constituents such as benzene in “widespread” or “prevalent” amounts in shale gas operations appear not to be supported when comparisons are made with air quality standards or when the relative amounts are compared to other sources such as vehicle exhausts. The relative contribution of shale gas activities in relation to conventional oil and gas development and other sources such as vehicle exhaust emissions must be taken into account in reports such as those from Wyoming and Fort Worth.

Emissions of methane have caused public concerns over global climate change since methane is a strong greenhouse gas. Venting or flaring of natural gas may take place during the fracturing and flowback phase of shale gas well development. However, many operators use "green completions" to capture and sell rather than vent or flare methane produced with flowback water. Onsite fugitive emissions of methane may take place from other sources as well, such as pressure relief valves of separators, condensate tanks, and produced water tanks. Although natural gas is confined in pipelines from production wells to the point of sale, methane emissions may also occur from offsite gas processing equipment and compressors notwithstanding the economic motive to minimize loss of natural gas. It is not known in the public realm the extent to which Best Management Practices (e.g. low-emissions completions, low-bleed valves) result in reduced methane and fugitive losses of methane.

2.2.8 Health Effects

Potential health effects have emerged as a primary area of controversy for shale gas operations. Several chemicals associated with shale gas wells and natural gas infrastructure have the potential for negative impact on human health. Chief among these are benzene and other VOC compounds as well as endocrine disruptors. The main sources are air emissions (described in Section 4.7 above) and surface and underground releases of fluids such as hydraulic fracturing fluids and flowback and produced water. Claims of shale gas effects include leukemia and other forms of cancer, headaches, diarrhea, nosebleeds, dizziness, blackouts, and muscle spasms.

In order for health effects to be determined for shale gas activities (as for other industrial operations), not only must the types and toxicity of releases be known, but also the chain of events from the point of release. The transport, possible attenuation, and exposure of toxic substances to receptors must be established in order for health risk to be evaluated. Many of the health effects allegations have focused on the potential toxicity of shale gas chemicals, such as VOCs and hydraulic fracturing fluids, but they provide little or no data on releases, migration, or actual exposure.

A large number of the reports are anecdotal rather than the results of scientific investigation. In many situations, separating the health impacts of shale gas from other potential sources such as smoking, living conditions, and travel on busy streets and highways is a complex task. Our society faces a problem in that benzene (and other VOCs), polynuclear aromatic hydrocarbons (PAHs), hazardous air pollutants (HAPs), and a variety of endocrine disruptors are widespread pollutants in our environment. For most of the population individual exposure to benzene and other VOs compounds is dominated by exposure to tobacco smoke, highway driving, time spent in gas stations, and time spent in urban environments.

Very few rigorous risk assessments of health effects of shale gas for other "upstream" oil and gas activities have apparently been conducted. In the absence of information specifically for shale gas, reference is made to other similar operations, including refineries and chemical plants. Both workers and nearby populations have been the subjects of these studies. Releases of VOCs (especially benzene) and endocrine disruptors have been investigated in several studies.

A short-term study of VOC levels in a sample of the population of DISH, Texas has been the only health-related study that is focused specifically on the possible impact of shale gas extraction. Although the response to this study from hydraulic fracturing antagonists was strong, some argue that the results were interpreted in a somewhat misleading manner or were not accurately communicated.

In general, none of the studies reviewed for this initiative showed a clear link between shale gas activities and documented adverse health effects, It may also be worth noting that the gas industry has been using hydraulic fracturing for over 50 years, but the studies examined in this review did not find any direct evidence for health impacts on workers in the industry or the public living near oil and gas industry activity.

2.2.9 Regulation or Policy Topics: Environmental Impacts

- Surface disturbances during construction and operation of well pad sites and associated roads and facilities may result in soil erosion, and transport of sediment and other contaminants, particularly during storm events. Clean Water Act regulations call for preparation and implementation of Storm Water Management Plans (SWMPs) to mitigate impacts of well pad sites greater than one acre in size.
- On a large scale, construction of a number of well pads in shale gas areas may result in land clearing (estimated at 34,000 to 83,000 acres) with resulting loss of forest and fragmentation of habitats.
- Research is needed to assess impacts and inform regulations for individual well site construction and operations and for large-scale regional impacts of land clearing and loss of habitats.
- Continued progress in the detailed disclosure of chemicals present in hydraulic fracturing fluid additives will enable a more complete analysis to be made of their potential impact and will help address public concern over their risk to water resources.
- Publicly available information on the additives to date indicates that the chemicals receiving attention are widely used in commercial products and are already dispersed in the environment.
- Risks of additional utilization of commonly used chemicals for hydraulic fracturing are mitigated by the fact that the depth of injection (several thousand feet) and the generally high biodegradability of the chemicals.
- Claims of migration of fracturing fluids out of the target shale zone and into aquifers have not been confirmed with firm evidence.

- The possible routes of escape such as induced or natural fractures or improperly plugged abandoned oil and gas wells as conduits for fracture fluid flow have not been substantiated.
- Many claims of impacts on water wells by shale gas activities have been made, but none have shown evidence of chemicals found in hydraulic fluid additives.
- Most claims have involved naturally-occurring groundwater constituents, such as iron and manganese, which may form particles in water wells that are released (resulting in change in color and increased turbidity in the water) as a result of vibrations and pressure pulses associated with nearby shale gas drilling operations.
- Water wells in shale gas areas have historically shown high levels of naturally-occurring methane long before shale gas development began; methane observed in water wells with the onset of drilling may also be mobilized by vibrations and pressure pulses associated with the drilling.
- Management of flowback water, which includes saline formation water from the shale ("produced water"), as a wastewater stream requires careful advance planning to maximize recycle and reuse and minimize the quantity of water required for fracturing and to be disposed after fracturing is completed.
- Gradually increasing contribution of produced water to flowback with time after fracturing results in increasing dissolved solids and associated challenges for reuse and disposal, particularly by land application or by discharge to surface water or to a publicly-owned treatment works (both requiring a permit).
- The potential risk from fracturing fluid additives in flowback water is smaller than that of naturally-occurring contaminants such as arsenic or high dissolved solids from produced water mixed with the flowback.
- Unplanned releases of natural gas in the subsurface during drilling may result in a blowout of the well or migration of gas below the surface to nearby houses, where the gas may accumulate in concentrations high enough to cause an explosion. Subsurface blowouts may pose both safety hazards and environmental risks. A major problem in these events is the limited ability to discern what is happening in the subsurface.
- Regulations for conventional oil and gas drilling address most issues of blowouts (such as through the use of blowout preventers) and other subsurface gas releases, primarily through provisions to ensure well integrity (especially for surface casing and cementing). But the added step in shale gas development of hydraulic fracturing through high downhole pressures may require upgrades of regulations in some states.
- Escape of methane from shale gas wells as a result of loss of well integrity (surface casing and cementing) may result in migration to water wells and homes along fractures or bedding planes. Methane accumulations in basements or wellhouses may result in explosions, but the rate of occurrence of such incidences is uncertain.

- Water requirements for hydraulic fracturing of shale gas wells are substantial (typically 4 to 6 million gallons per well), but the consumption may be relatively limited compared to other water users in the area. And for many shale areas, the withdrawalS may be sustainable for prolific aquifers – and particularly for surface-water supplies in high rainfall regions.
- Management of leaks and spills at the well pad site and at off-site facilities such gas pipelines and compressor stations for shale gas drilling is similar to conventional gas development. But shale gas wells also make use of hydraulic fracturing fluids and associated chemical additives, and they have impoundments for storage of flowback and produced water, both of which may increase risks of spills and other releases. Chemical additives may pose a higher risk in their concentrated form while being transported or stored on-site than when they are injected into the subsurface for hydraulic fracturing.
- Emissions of volatile organic carbon compounds (VOCs) are the primary area of concern for air quality, particularly in ozone non-attainment areas like Fort Worth; however, the shale gas contribution to VOC emissions is quite limited in comparison to other sources such as vehicle exhaust.
- Methane releases during shale gas operations have caused concern over contribution to global climate change, since methane is a much stronger greenhouse gas than carbon dioxide. However, many operators already recover most methane during "green completions". Shale gas, like natural gas in general, may be subject to more stringent controls in the future if global climate change regulations are put in place.
- The primary concern for health effects of shale gas development are benzene and other VOC compounds, primarily as air emissions and from liquid sources such as flowback and produced water. Much research remains to be done on the toxicity, transport, exposure, and response of receptors to shale gas VOC emissions to verify claims of impacts on health, such as cancer, headaches, nosebleeds, and other symptoms.

2.3 Regulatory and Enforcement Framework

Effective regulation of shale gas development must not only provide adequate protection of human health and the environment, but also build upon what has been developed previously. Shale gas regulation is accomplished within a solid framework of laws and regulations that have been developed for conventional oil and gas over many decades. Although many of these regulations were put in place before the advent of major shale gas production, they are nevertheless applicable.

Shale gas development is regulated at almost all levels of government, but in general the principal regulatory authority lies with the states. Compliance with regulatory requirements for shale gas development is being accomplished in many states through additions to and modifications of existing regulations. The regulatory framework for shale gas is described below for federal laws and regulations and for state, regional, and local requirements. The description is then rounded out with an evaluation of regulatory enforcement by the states. Because the regulatory situation is similar for two similar resources – shale oil and tight gas – they are included in the description and analysis.

2.3.1 Federal Regulation

Shale gas development is subject to many federal regulations (as is the case for other oil and gas operations), but has also received exemptions from a number of regulations that normally would have been applicable. Federal regulation has also led to cooperative efforts between agencies and the private sector to optimize the effectiveness of applicable shale gas regulations.

2.3.1.1 Applicable Legislation and Regulations

A number of federal laws and associated regulations apply to various phases of shale gas development.

Clean Water Act (CWA). Stormwater controls aim to minimize erosion and sedimentation during construction (including construction of oil and gas sites), and the CWA prohibits the dumping of any pollutant into U.S. waters without a permit. The EPA intends to propose CWA standards for the treatment of wastewater from shale gas wells in 2014.

Clean Air Act (CAA). Under recently-proposed CAA regulations, shale gas operators will have to control volatile organic compound (VOC) emissions from flowback during the fracturing process by using a VOC capture techniques called "green completion."

Endangered Species Act (ESA). Under the ESA, operators must consult with the Fish and Wildlife Service and potentially obtain an incidental "take" permit if endangered or threatened species will be affected by well development.

Migratory Bird Treaty Act (MBTA). Operators will be strictly liable for any harm to migratory birds under the MBTA and therefore must ensure that maintenance of surface pits or use of rigs does not attract and harm these birds.

Emergency Planning and Community Right-to-Know Act (EPCRA) and Occupational Safety and Health Act (OSHA). Under EPCRA and OSHA, operators must maintain material safety data sheets (MSDSs) for certain hazardous chemicals that are stored on site in threshold quantities.

Comprehensive Environmental Responsibility, Compensation, and Liability Act (CERCLA). Under CERCLA, operators must report releases of hazardous chemicals of threshold quantities and may potentially be liable for cleaning up spills.

2.3.1.2 Exemptions from Federal Regulations

In addition to having to comply with several federal requirements, shale gas developers, like other oil and gas operators, enjoy several federal exemptions.

Resource Conservation and Recovery Act (RCRA).

Most wastes ("exploration and production" or "E&P" wastes) from fracturing and drilling are exempt from the hazardous waste disposal restrictions in Subtitle C of the RCRA, meaning that states – not the federal government – have responsibility for disposal procedures for the waste. Although Subtitle C of RCRA originally covered oil and gas wastes – thus requiring that operators follow federally-established procedures for handling, transporting, and disposing of the wastes – in the 1980s Congress directed the EPA to prepare a report on oil and gas wastes and determine whether they should continue to be federally regulated. In its report, the EPA noted

that some of the wastes were hazardous but ultimately determined that due to the economic importance of oil and gas development and state controls on the wastes, federal regulation under RCRA Subtitle C was unwarranted.

The EPA did note some state regulatory deficiencies in waste control, however, and relied on the development of a voluntary program to improve state regulations. This voluntary program has since emerged as the State Review of Oil and Natural Gas Environmental Regulations (STRONGER), a non-profit partnership between industry, nonprofit groups, and regulatory officials. STRONGER has developed guidelines for state regulation of oil and gas wastes, periodically reviews state regulations, and encourages states to improve certain regulations.

Despite the RCRA exemption, some states treat oil and gas wastes as unique wastes under their waste disposal acts. Pennsylvania, for example, treats certain oil and gas wastes (including flowback water from fracturing) as "residual" wastes under its state Solid Waste Management Act and has special handling and disposal requirements for these wastes. Furthermore, in all states, non-exempt oil and gas wastes still must be disposed of in accordance with federal RCRA requirements.

Comprehensive Environmental Responsibility, Compensation, and Liability Act (CERCLA).

CERCLA holds owners and operators of facilities, those who arrange for disposal of waste, and those who accept hazardous substances for disposal liable for the costs of hazardous substance clean-up, and the Act also requires reporting of certain hazardous waste spills. CERCLA exempts oil and natural gas from the hazardous substances that trigger these liability and reporting requirements, however. Oil and gas operators still must report spills of other hazardous wastes of a threshold quantity, however, and may ultimately be liable for clean-up of these wastes.

Clean Water Act (CWA).

Typically, industrial facilities that generate stormwater runoff (as "pollutant" under the Act) must obtain a stormwater permit under the Clean Water Act for this runoff; they are required to have a permit both for constructing the facility (at which point soil sediment may run off the site)

and operating it (at which point polluted substances may continue to run off the site during precipitation events, for example). The Clean Water Act does not require oil and gas operators, however, to obtain a permit for uncontaminated "discharges of stormwater runoff from . . . oi l and gas exploration, production, processing, or treatment operations."

In the Energy Policy Act of 2005 (EPAct 2005), Congress expanded the definition of oil and gas exploration and production under the Clean Water Act – a definitional change that potentially allowed for the exemption of more oil and gas activity from stormwater permitting requirements. The EPA subsequently revised its regulations to exempt oil and gas *construction* activities from the NPDES stormwater permitting requirements. The 2008 Ninth Circuit case *Natural Resources Defense Council v. EPA*, however, vacated these regulations, and the EPA has reinstated its prior requirements for stormwater permits along with "clarification" based on EPAct 2005.

In sum, oil and gas operators must obtain a stormwater permit under the Clean Water Act for the construction of a well pad and access road that is one acre or greater, but they need not obtain such a permit for any uncontaminated stormwater from the drilling and fracturing operation. Some states and regional entities such as New York and the Delaware River Basin Commission, however, have proposed to require stormwater permitting that addresses both the construction and operation of gas wells that are hydraulically fractured.

Safe Drinking Water Act (SDWA).

Fracturing operators also are exempt from the SDWA, which requires that entities that inject substances underground prevent underground water pollution. The SDWA applies only to waste from fracturing and drilling that is disposed of in underground injection control wells; operators need not obtain an SDWA underground injection control (UIC) permit for the fracturing operation itself. If operators use diesel fuel in fracturing, however, they are not exempt from SDWA. The EPA currently is developing UIC standards for fracturing with diesel fuel.

2.3.2 State, Regional, and Local Regulation

The primary regulatory responsibility for shale gas development is at the state level. State agencies both administer federal environmental regulations and write and enforce many state regulations covering nearly all phases of oil and gas operations. The degree of local regulation, such as by municipalities, is also subject to state control. Sixteen states that have produced – or soon will produce – shale gas are included in the scope of this investigation: Arkansas, Colorado, Kentucky, Louisiana, Maryland, Michigan, Montana, New Mexico, New York, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, West Virginia, and Wyoming. In general, regulations applying to shale gas also apply to shale oil, so states producing shale oil are included in the above list. STRONGER, as noted above, is a partnership including regulatory officials and industry representatives that develops guidelines for state oil and gas regulations. STRONGER also periodically reviews the regulations of individual states.

An effective way of reviewing state, regional, and local regulations applying to shale gas is to consider the stages of the shale development process. The stages of the cycle are generally as follows:

- Shale Gas Exploration
- Well Pad Siting and Construction
- Equipment Transport
- Well Drilling and Casing
- Hydraulic Fracturing
- Water Supply and Consumption
- Air Emissions Controls
- Surface Water and Spill Management Controls
- Wastewater and Solid Waste Management
- Site Remediation
- Groundwater Contamination

State regulatory provisions, shown below, are organized according to these stages. The descriptions are derived from Section 5 of this report and are intended to be representative rather than comprehensive.

2.3.2.1 Shale Gas Exploration

The occurrence of shale gas in the US is well understood in a general way in the large sedimentary basins as described in Section 2. Additional, more detailed, delineation may be required when a specific development project is undertaken. The seismic method of exploration, a type of geophysical technology, may be used for locating suitable shale gas targets. In the seismic method, energy is introduced into the subsurface through explosions in shallow "shot holes", by striking the ground forcefully (with a truck-mounted "thumper"), or by vibration methods. A portion of this energy returns to the surface after being reflected (or refracted) from the subsurface strata. This energy is detected by surface instruments, called geophones, and the information carried by the energy is processed by computers to interpret subsurface conditions. The results are then used to guide shale gas drilling locations.

Exploration by seismic methods is subject to an array of safety, environmental, and related regulations. In many states, a permit must be obtained before seismic exploration can proceed. Some states have general environmental protection provisions, whereas others have more detailed stipulations, such as minimum distances from springs or water wells. General protection provisions often stipulate prevention of environmental damage, protection of natural resources such as surface water and groundwater, and restoration or prevention of impacts of large seismic equipment, such as shot hole rigs, thumpers, or vibration-inducing trucks. Minimum distances of seismic activities from roads, residences, schools, commercial buildings, and other cultural features may also be required. Safety regulations apply to the use of explosives in shot holes, such as a license for blasting. Plugging of shot holes is normally required after the survey to prevent the introduction of contaminants from the surface.

2.3.2.2 Well Pad Siting and Construction

Once the best location for a shale gas well (or wells) has been ascertained by exploration methods, a site for the well pad and associated facilities must be established. Besides the pad and

access road, accommodation must be made for drilling mud and surface pits or containers, below-grade tanks, land application sites, trucks, and other well drilling materials. Regulations for drilling pad siting are designed to protect both natural resources and cultural features, such as residences, private water wells, public water supplies, parks, and commercial property. Natural features identified for protection include streams, floodplains, wetlands, watersheds, aquifers, and similar components of the environment. The principal method of assuring protection under the siting regulations is by designation of setbacks – minimum distances from the well pad and facilities to the feature being protected. In some cases, buffer zones are established within which the type of shale gas activity allowed is designated.

After a suitable location has been found (and a permit obtained, if required), the well pad, access road, and associated facilities are constructed and operated. Often, the well pad is used for drilling a number of individual wells that extend in different directions in the subsurface. The well pad typically requires about 3.5 acres and the access road 0.1 to 2.8 acres, depending on length.

One of the most important regulatory provisions, besides the setback as described above, is stormwater permitting as well as other Clean Water Act requirements. In general, Storm Water Management Plans (SWMPs) are required when a well pad site is greater than one acre in size. In many states, a "general industrial" stormwater protection permit is issued, which is based on "best management practices" (BMPs). The general industrial permit requires stormwater controls that are not individualized by site. The BMPs help control erosion and sedimentation during pad and access road construction and are generally consistent among the states.

Some states also have regulations for wildlife protection, which in many cases call for a BMP to minimize surface disturbances and prevent habitat fragmentation. And some states call for use of netting over pits to protect birds and may include a reminder of requirements of the Endangered Species Act where applicable. Certain regional jurisdictions, such as the Delaware River Basin Commission, have proposed to regulate many stages of shale gas development, including requirement for a Non-Point Source Pollution Control Plan.

2.3.2.3 Equipment Transport

During construction of the well pad, access road, and other drilling facilities, truck traffic is often substantially increased. Regulatory and other responses to increased traffic typically take place at the local rather than the state level. The increased traffic, along with the large size of the trucks and equipment that is being transported, gives rise not only to crowded roads (possibly necessitating road expansion), but also to greater stress on the roads and associated higher costs of road repair and maintenance. One estimate indicates a need for 100 to 150 truckloads of hydraulic fracturing equipment and another 100 to 1000 loads for the fracturing fluid (when trucks rather than pipelines are used) and sand for proppants. In some cases, operators are required to post bonds to help deal with rises in heavy traffic.

Some communities require operators to enter into a road repair or maintenance agreement with the city. Such agreements designate routes to be used in addition to bonding requirements, how operators must repair damage, and damage for which the city will not be liable. Some cities also require operators to pay road remediation assessments to cover the increased costs of repairs.

2.3.2.4 Well Drilling and Casing

Some of the most detailed state oil and gas regulations cover the well drilling and casing stages. There is considerable variation among states in the current regulatory provisions. In general, the primary emphasis is on surface casing integrity, cementing of the casing, and blowout prevention. Many of the existing regulations address well construction for conventional oil and gas operations, but some states are updating provisions specifically for shale gas drilling. The regulations address both short-term integrity during well drilling and formation fracturing and long-term operation of a producing well.

Protection of aquifers as sources of fresh water is the main objective of surface casing and cementing requirements. Such protection is provided from drilling fluids, methane leakage during drilling, and fracturing fluids during hydraulic fracturing. These provisions include depth of placement of surface casing, strength of the casing, and placement and strength of the cement that is injected around the surface casing. In addition to these requirements, a well log ("bond log") may be specified as a check that sufficient integrity is accomplished.

Regulations for blowout prevention cover both losses of control at the wellhead and in the subsurface and both the drilling and hydraulic fracturing phases. The depth that surface casing is required to be set may be specified in feet for all wells or on a well-by-well basis to account for site-specific aquifer conditions. Some states call for detailed pressure testing of the surface casing and cement jobs. Many oil and gas producing states have blowout prevention regulations in place for drilling into formations with unknown or abnormal pressures. Prevention of blowouts during the hydraulic fracturing phase is described in a previous section.

2.3.2.5 Hydraulic Fracturing.

Regulations for hydraulic fracturing have been put in place in many states for conventional oil and gas wells, but they also apply to hydraulic fracturing for shale gas. Such regulations emphasize the proper function of processes and equipment with little direct reference to groundwater or surface-water protection. A few states (e.g., Oklahoma, West Virginia) have water pollution prevention requirements for oil and gas wells in general, but they are not specific to hydraulic fracturing. These general provisions do not provide specific guidance for operators, but may be used in litigation if pollution occurs.

Some states require notification of the responsible agency when hydraulic fracturing is planned so that operations can be observed or supervised by the agency. STRONGER recommends that agencies require prior notification and follow up reporting of hydraulic fracturing operations.

One of the primary issues of aquifer protection is the existence of old, improperly plugged oil and gas wells that may provide conduits from the target fracture zone upward to aquifers. Another risk that must be managed is underground blowouts that may occur during the high-pressure phase of hydraulic fracturing, which is addressed in another section.

Most relevant regulations for hydraulic fracturing focus on the chemicals used, but the main focus is not so much on water quality protection as it is on human exposure and medical responses. Some of the regulations apply to chemical spills, with a focus on the transport of chemicals as addressed by the US Department of Transportation as well as state-level agencies. Regulations for chemical spills are covered in another section below.

Disclosure of chemicals used in hydraulic fracturing has become an issue in many states, but the focus of current regulations is on human exposure and meeting requirements of federal laws (EPCRA, OSHA). Many of the chemicals are required to have Material Safety Data Sheets (MSDSs) available at the point of storage and use.

2.3.2.6 Water Consumption and Supply

Shale gas development has a higher water requirement than most conventional oil and gas drilling because of the need for large quantities of water for hydraulic fracturing. A shale gas well may require as much as 300,000 gallons per day per well, and a total fracturing treatment may require up to seven million gallons (or more) of water. The amount of water used in relation to other consumptive uses in a shale gas area has become a major component of the shale gas controversy, particularly in areas of drought, such as Texas in recent years.

Water supplies for fracturing operations may come from surface water, groundwater, or a combination of both. Surface-water withdrawals are subject to the availability of water rights as determined by water law, a form of common law of the various states. Water rights are granted in the eastern states generally under riparian water law, whereas such rights are generally subject to prior appropriation rights in the western states. Water rights for shale gas are determined primarily by ownership of land adjacent to the surface water source under the riparian rights doctrine. Under the prior appropriation doctrine such rights depend on availability of water after the needs of earlier water rights holders have been met.

In many states, the straightforward concepts of the two common law doctrines have been supplemented by statutory law, which may have additional requirements such as permits for withdrawal or reporting of amounts withdrawn (or both). In some drainage basins, additional controls of water withdrawal and use are imposed by non-state Congressionally-mandated organizations, such as the Delaware River Basin Commission and Susquehanna River Basin Commission.

Regulation and control of groundwater withdrawals are also quite variable from state to state and must be ascertained by shale gas operators to be assured of water availability from these sources. In some states, for example, groundwater is owned by the surface owner and subject only to

reasonable use requirements (if at all), whereas in other states groundwater is a public asset owned by the state and subject to permits from state agencies for withdrawal of water.

Some states have responded to the water needs of shale gas drilling with added or modified water use requirements. These changes focus on the processes of allocating water rights, granting permits for withdrawal, and reporting of amounts withdrawn. Some requirements address the water quality implications of large water withdrawals and regulate on the basis of need to maintain baseline water quality standards or to protect riparian ecosystems. In states where this connection is made, additional regulatory authorities, such as traditional state water quality agencies, many enter the picture for securing water for share gas drilling.

Some states are beginning to require increased reuse and recycling of flowback and produced water not only to reduce water consumption but also to moderate wastewater disposal impacts.

2.3.2.7 Air Emissions Controls

Shale gas development is subject to both federal and state air emissions regulations established by the Clean Air Act (CAA) and state-level legislation. Many of the CAA provisions are delegated from the US EPA to the various states' environmental agencies. The major air pollutant sources of shale gas drilling and fracturing are the drilling and associated equipment, tanks and pits for flowback water, flared gas, and methane sources at the wellhead and from pipelines and compressors.

Oil and gas operations, and shale gas in particular, are subject to regulations for "criteria pollutants" (sulfur dioxide, nitrogen oxides, ozone, particulate matter, carbon monoxide, and lead) and "hazardous air pollutants" (HAPs, including 187 compounds). However, these regulations focus on "major" sources, which generally do not include oil and gas operations for the sources listed above specifically. If regulated at all, oil and gas sources of criteria pollutants and HAPs fall under state minor source programs. The strictest criteria air pollutants regulations apply to areas not meeting established maximum ambient air standards, which are referred to as "non-attainment" areas.

Compressor stations are an example of an oil and gas emission source of criteria pollutants that are subject to technology-based emission controls referred to as new source performance standards (NSPS). Volatile organic carbon (VOC) compounds is another type of pollutant that is subject to regulation under the CAA. The US EPA has proposed VOC emission regulations that would apply to hydraulic fracturing. A number of states (e.g. Colorado, Wyoming, New York) have also adopted VOC regulations that include such requirements as emissions reductions, siting stipulations (distances from buildings), and VOC capture requirements.

Municipalities, including Fort Worth in the Barnett shale area, have implemented air emissions controls such as VOC capture requirements, reduced emissions stipulations, and exhaust mufflers. The primary sources of natural gas emissions from shale gas operations are wellhead releases and leaks from pipelines and compressors. Although much concern has been expressed about methane emissions as a strong greenhouse gas, regulations for its control have not been promulgated.

2.3.2.8 Surface Water Protection and Spill Management Controls

Shale gas development, like conventional oil and gas, is subject to many federal and state regulations to protect surface-water resources from intentional discharges and unintentional spills and other releases. The Clean Water Act (CWA) stipulates that a permit (National Pollutant Discharge Elimination System, NPDES permit) must be obtained for discharges to surface water, as described in below. Stormwater runoff must also be controlled and is subject to an NPDES discharge permit.

A source of primary concern for shale gas well production is the potential for spills or other releases at the well pad site or during transportation of chemicals, fuels and other materials. Other potential sources of release are diesel fuel for the drilling rig and on-site equipment, storage tanks and pits that may leak or overflow, drilling mud, flowback and produced water storage, and hydraulic fracturing fluid. The CWA, as amended by the Oil Pollution Act (OPA) addresses spills and other accidental releases, primarily through a requirement for a Spill Prevention Control and Countermeasures (SPCC) plan for adequate responses to releases. Most states require an SPCC plan or equivalent for oil and gas operations as well as a statewide plan

for response to spills and other releases. SPCC plans include not only prevention and control, but also reporting and cleanup requirements.

When a release involves hazardous chemicals, regulations pursuant to The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) apply if the amount exceeds a threshold quantity.

In most states, the provisions of these federal laws have been delegated by the US EPA to state environmental regulatory agencies. These agencies are also responsible for state laws and regulations that have been prepared in addition to the federal requirements. Some states have recently updated their laws and regulations to address spills of chemicals and other materials specifically related to shale gas drilling and hydraulic fracturing, such as new or additional chemicals.

2.3.2.9 Wastewater and Solid Waste Management

Disposal of liquid and solid wastes from shale gas operations is subject to a host of federal and state regulations that apply to oil and gas operations in general as well as shale gas specifically. Disposal of drilling and fracturing wastes pose a number of potential environmental and health risks. Management of these wastes may be the greatest challenge of shale gas regulation by state agencies having the responsibility. Many of the wastes are the same as or similar to those of conventional oil and gas production, but some – notably flowback water and produced water – are somewhat unique to shale gas. Drilling fluids comprise most of the liquid wastes that are not specific to shale gas development. Drill cuttings are the primary solid wastes produced by both conventional and shale gas operations.

Regulations for waste storage primarily address temporary pits and tanks for drilling fluids and cuttings and for flowback and produced water. The regulations include requirements for pit liners, freeboard (excess volumetric capacity), and closure, all of which have the objective of preventing soil and water contamination. Some states are adopting provisions for "closed loop" drilling systems, which require that drilling and fracturing wastes must be stored in tanks rather than pits that are more likely to leak and enter the surrounding environment.

Although some states have only general requirements not to contaminate soils, surface water or groundwater, most have specific mandates for individual waste streams. Waste disposal requirements for drilling and hydraulic fracturing vary substantially from state to state and the type of waste being disposed of. Wastewater disposal is primarily by underground injection in western and southern shale gas producing states and by discharge to publicly owned treatment works (POTWs) in eastern states. Federal requirements for wastewater discharge to surface waters and POTWs under the CWA (in the form of an NPDES permit) have been delegated to state agencies for many shale gas producing states.

Wastewater discharge to a POTW – which is necessitated by less desirable subsurface conditions for underground injection wells in eastern states – has become controversial and has been prohibited by some of the shale gas producing states. Other states require pretreatment before discharge to a POTW. The US EPA has announced that wastewater treatment standards will be developed for shale gas wastewater by 2014.

In addition to administering federally delegated regulatory and permitting program, states have added their own restrictions on disposal. Some states, including Pennsylvania, prohibit discharge to POTWs, and other states are reevaluating the practice of onsite land disposal of wastes.

In general, increased emphasis is being placed on requirements for wastewater reduction through recycle and reuse of hydraulic fracturing fluids (which has the added benefit of produced water requirements) in a number of states.

In some shale gas areas, operators manage wastes at a centralized waste disposal facility that accepts RCRA-exempt waste from multiple well sites. These facilities may be subject to general state requirements such as best management practices to protect human health and the environment. They may also be subject to specific requirements, such as an operating plan (to address emergency response, site security, inspection and maintenance, safety requirements), water well monitoring, and surface water diversion for storm events.

Another important category of wastes for management is naturally occurring radioactive material (NORM), which is produced in both drill cuttings and in flowback and produced water. Federal

regulations do not address NORM so its control takes place at the state agency level. In many cases NORM regulation is split among two or more state agencies, as in Texas.

2.3.2.10 Site Remediation

The requirements for plugging and abandoning shale gas wells at the end of their life cycle, as is the case for unconventional oil and gas wells, are specified by state agencies. States also have responsibility for specifying site (drill pad and surrounding area) restoration requirements. The objective is often to restore the site to its former use. Typically operators are required to remove the contents stored in pits, test for contamination and clean up as necessary, and revegetate the site within a reasonable time. For shale gas wells, restoration should consider testing and remediation of hazardous chemicals that may have been released as a result of hydraulic fracturing procedures.

2.3.2.11 Groundwater Contamination

Protection of shallow aquifers in conventional oil and gas operations through such measures as surface casing and cementing and drilling mud pit liners needs to be a primary focus for shale gas wells. For example, the use of additional chemicals and proppants for hydraulic fracturing and the potential for groundwater impacts by construction problems or failures in the upper part of the well bore require additional monitoring and protective measures. The focus of media attention specifically on the fracturing process has highlighted concern about potential groundwater impacts.

A few states, such as Pennsylvania, have supplemented oil and gas regulations with requirements directed specifically to shale gas wells in the Marcellus. Establishing pre-drilling groundwater quality through a baseline monitoring program, which has not been routinely performed as shale gas well locations in the past, will enable impacts to be detected and mitigative actions to be taken when required. Some states, for example Colorado and Pennsylvania, have implemented measures to protect water supplies during shale gas operations. These measures do not require systematic, well-designed monitor well programs, but instead provide for monitoring of existing water wells, replacement of water supplies if contamination occurs, and holding operators legally responsible for contamination.

2.3.3 State Enforcement of Regulations

Equally as important as having well-developed regulations on the books is adequate enforcement by staff both in the office and conducting field inspections. Regulatory enforcement can be measured in several ways, including number of staff assigned, inspections conducted, and violations recorded. The type and severity of violations demonstrate the type of adverse effects being addressed by the regulatory programs. Regulatory enforcement was analyzed for 15 of the 16 states whose regulations were assessed as described in the preceding section.

2.3.3.1 Enforcement Capacity

The capacity of an agency with regulatory responsibility was assessed by gathering information on the number of staff assigned to the inspections and the number of inspections actually accomplished for the years 2008 to 2011. The information included many of the 16 states including in the survey of regulations: Louisiana, Maryland, Michigan, Montana, New Mexico, North Dakota, Texas and Wyoming. The following parameters were included in the assessment:

- Number of active shale gas, tight sands, and/or shale oil wells, 2008
- Total number of field inspectors in agency, 2008
- Of total inspectors listed above, total number assigned to shale gas wells, 2008
- Number of field inspections, 2008
- Number of attorneys devoted enforcing activities that oil and gas wells, 2008

Texas had the highest number in all categories. A wide variation was found in the ratio of enforcement staff and field inspectors to the number of shale gas and similar wells in the state. Part of the variation is due to differences in methods of reporting among the states. Despite this variation, it was found that most states with current shale gas and related development have enforcement capacity necessary to address at least some complaints associated with oil and gas development and to conduct independent enforcement actions.

Some states have much higher enforcement capacity, and larger numbers of inspections, than others. This higher capacity more than likely influences the total number of violations noted and enforcement actions taken. A higher capacity may also result in more representative violations.

2.3.3.2 Development Activities and Environmental Effects

Shale gas development activities addressed by state violation and enforcement actions were also evaluated for Louisiana, Michigan, New Mexico and Texas for the following:

Construction of access road and well pad
- Erosion and sedimentation

Maintenance of site: vegetation, signs, fencing
- Fencing
- Signs and labeling
- Site maintenance (clearing weeds, for example)

Drilling (and potentially fracturing)
- Air quality
- Casing and cementing
- Commingling oil and gas
- Failure to prevent oil and gas waste
- Fire
- Gas or oil leak at wellhead/venting
- Noise
- Odors
- Surface spill condensate
- Surface spill contaminant not indicated
- Surface spill diesel
- Surface spill drilling mud
- Surface spill oil
- Surface spill produced water
- Wellhead and blowout equipment
- Well spacing

Fracturing-specific violations and complaints
- Fracturing
- Groundwater contamination (complaints only)
- Surface spill frac fluid

Storage of waste
- Pits and tanks: construction, operation, maintenance, closure
- Secondary containment

Disposing of waste
- Land application of waste
- Improper disposal

Plugging and site closure
- Plugging
- Removing equipment, filling ratholes
- Well not secured if shut in

Procedural violations: financial security, permits, tests and drills, reporting
- Financial issues (bonding, etc.)
- Permitting, plat filing, reporting
- Tests and drills

Other
- Water well construction

The percentages are violations each of the states and the categories were found as follows:

	LA	MI	NM	TX
Total violations (number)	158	497	77	72
Construction of access road and well pad	0%	1%	0%	0%
Maintenance of site: vegetation, signs, fencing	20%	55%	16%	6%
Drilling (and potentially fracturing)	10%	30%	58%	15%
Fracturing-specific violations and complaints	0%	0%	11%	0%
Storage of waste	41%	4%	1%	1%
Disposing of waste	0%	0%	2%	21%
Plugging and site closure	0%	10%	0%	1%
Procedural violations	20%	0%	7%	45%
Other	0%	0%	0%	0%

Except for Louisiana, few of the violations noted in the table resulted in formal enforcement actions. All of the violations were for Louisiana resulted in issuance of administrative orders.

2.3.3.3 Environmental Effects of Violations and Enforcement Actions

The types of environmental effects associated with state violation and enforcement actions were also evaluated. First, an interpretation of the effects of the actions was made in terms of "gravity of environmental effect" in five categories, and the percentages of total violations were computed, with the following result:

Gravity of Environmental Effect	Louisiana: Haynesville Shale wells 2009-2011	Michigan: Antrim Shale wells 1999-2011	New Mexico: tight sands & shales (non-exhaustive) 2000-2011	Texas: fractured shale wells, FY 2008-2011
	158 total violations	497 total violations	77 total violations	72 total violations
	Percent of total violations	Percent of total violations	Percent of total violations	Percent of total violations
Procedural	60	33	26	53
Minor—no effect	31	28	1	1
Minor effect	2	25	20	8
Substantial	7	15	42	29
Major	1	0	12	8

Generally, this information suggests that many of the violations are procedural and represent no environmental effects; are minor with no effect – meaning that an inspector noted a flaw in a pit or casing job, for example, but did not note any release of contaminant to the environment as a result of that flaw; or represent minor effects, such as small releases. The higher percentage of substantial and major effects noted for New Mexico could potentially result from several factors. New Mexico may focus more closely on environmental effects that are technical violations, such as a failure to post a sign. Alternatively, there could be more significant problems in New Mexico, or the smaller size of the data set could skew the percentages. Most of the major violations in New Mexico involved large spills of produced water.

In Pennsylvania, three activities at one site led to a consent order and agreements as well as a substantial penalty. The Pennsylvania agency also issued notices of violation for 80 additional activities ranging from improper casing and cementing to discharge of flowback water. Violations in New Mexico were for land application of produced water, a spill of hydraulic fracturing fluid, release of oil (with remediation required), failure to obtain well drilling permits, constructing surface pits, and disposing of produced water above the in a pit. Michigan actions

included a compliance case for soil contamination at a wellhead and notices of non-compliance for failure to plug wells after production ended.

A limited number of the violations was noted in response to complaints. These included problems with seismic testing, compressor sounds and other noise, weed growth, brine spraying around a wellhead, venting gas from wellheads, an overflowing production pit, odors, equipment oil leaks, and improper reseeding of well sites. Overall, the data collected showed few complaints made to agencies. However this could be because of lack of records or no link being established between compliance and enforcement actions.

2.3.4 Regulation or Policy Topics: Regulatory and Enforcement Framework

The topics for regulation or policy consideration for shale gas regulation may be considered for Federal regulation; state, regional and local regulation; and state enforcement of regulations.

2.3.4.1 Federal Regulation

- In general, few Federal regulations are currently directed specifically to shale gas or to oil and gas generally; applicable regulations are pursuant to broader environmental laws for air, water, waste, and other areas.
- A number of exemptions from federal regulations have been granted for oil and gas activities and have been applied to shale gas development.
- In some states, similar requirements that are exempted from federal regulation are imposed at the state level.

2.3.4.2 State Regional and Local Regulation

- Primary regulatory authority for shale gas is at the state level; many federal requirements have also been delegated to the states.
- Most state oil and gas regulations were written before shale gas development became important; shale gas development is therefore subject to body of previously-developed oil and gas regulations in many of the states in the shale gas areas.
- Regulations for many shale gas activities and their consequences are applicable to oil and gas activities generally and not just to shale gas specifically, including exploration activities.

- Some states have revised regulations specifically for shale gas development; regulatory gaps remain in many states, including the areas of well casing and cementing, water withdrawal and usage, and waste storage and disposal.
- A number of organizations and activities are underway, including the Groundwater Protection Council (GWPC) and State Review of Oil and Natural Gas Regulations (STRONGER), to develop and improve state regulation of oil and gas operations, including shale gas development..
- Recent regulatory revisions focus on three prominent concerns: 1) proper casing of wells to prevent aquifer contamination; 2) disclosure of hydraulic fracturing chemicals; and 3) proper management of large quantities of wastewater.
- Any new regulations – and modification of existing provisions – should be developed with a strong foundation in science, with well-supported research into areas requiring better understanding to support regulations.
- Care must be taken to focus regulations on the most urgent issues (e.g. surface spill prevention) is well as areas of greatest public concern
- States not having regulations for blasting in environmentally sensitive areas or for shot hole plugging during the shale gas exploration phase may want to consider adding these requirements.
- Particularly in states not having previous extensive oil and gas development, new or additional site-specific regulations, such and stormwater requirements, may be needed to minimize surface disturbances and impacts on environmentally sensitive areas.
- For protection of sensitive areas and cultural features such as schools and public water supplies, state regulations may need to set minimum distances (setbacks) from drill pads and other facilities.
- States may need to specify more uniform requirements for truck traffic and other community impacts of shale gas activities – an area currently addressed primarily by municipalities and other local governments.
- More consistent requirements from state to state may be needed to ensure well integrity (surface casing and cementing) to prevent blowouts and leakage – but with provisions for flexibility to meet site-specific drilling and well completion conditions.
- Additional and consistent regulations for control of air emissions may be needed to address all phases and facilities of shale gas development, including conventional

("criteria") and hazardous air pollutants, fugitive emissions of natural gas from pipelines and other facilities, and gas releases during drilling, fracturing and well completion ("green completions").

- States may need to continue to modify common law rights systems (e.g., riparian, prior appropriation) with legislation to strengthen permitting and reporting of surface water withdrawals for shale gas development.
- States may also need to supplement current laws and practices for groundwater withdrawals and associated permitting for shale gas development.
- Disclosure of the chemical contents of additives to hydraulic fracturing fluids may be needed on a more uniform basis among state regulatory authorities.
- Additional requirements to ensure well integrity during hydraulic fracturing (e.g., strength testing of casing, bond logs) may be needed in some states.
- Updates may be needed for requirements of spill prevention and contingency plans in some states to take into account new chemicals, such as fracturing fluid additives, that are transported to and used at the drill site.
- Updates of state regulations may be needed to require adequate baseline (pre-drilling) groundwater sampling, analysis, and/or monitoring to improve the basis for determining if shale gas activities have an impact on water quality in nearby aquifers.
- Updates may also be required for establishing responsibility for groundwater impacts and for replacing water supplies when water wells are affected.
- With the additional wastewater streams of flowback and produced water from shale gas development, states may need to consistently update regulations for waste storage in pits to specify liners, minimum freeboard, closure methods, and other requirements.
- States may also need to more uniformly require a plan for disposal of wastes (including drilling fluids, drill cuttings, and flowback and produced water) and to ensure that the methods of disposal (e.g., centralized facility, surface discharge with permit, discharge to POTW or injection well, land application) conforms with regulations and best practices
- States may need to update or put in place adequate regulations for disposal of wastes containing naturally-occurring radioactive material (NORM) – as for oil and gas operations in general.

- States may need to review requirements for site restoration after drilling and well completion to ensure that shale gas specific characteristics (e.g., fracturing fluid chemicals, flowback and produced water) are taken into account.

2.3.4.3 State Enforcement of Regulations

- Regulations that are effective for protecting human health and the environment depend not only on the content of the regulations but also on how well they are enforced by regulatory agencies.
- Evaluation of state enforcement is hindered by several factors, including differing methods of collecting, organizing, and recording violations and enforcement actions; variances in the completeness of records; and responsiveness of agencies to information requests.
- Enforcement capacity, as measured by staff levels, is highly variable among the states, particularly when measured by the ratio of staff to numbers of inspections accomplished.
- Preliminary findings from four states (Louisiana, Michigan, New Mexico, Texas) found over 800 violations involving most phases of shale gas operations – construction, site maintenance, drilling and fracturing, waste storage and disposal, site closure and well plugging, and operations procedures. But the comparison of these violations with those for conventional gas development is not known.
- When violations are classed into categories ranging from merely procedural to major environmental impact, 58% were found to be procedural or having little or no impact, and 42% indicated a major, substantial or minor effect.
- Surface spills, improper disposal of oil and gas wastes, and problems with leaking pits or tanks are relatively common violations, which can be prevented.
- Most violations were from operations in common with conventional gas drilling rather than shale gas specific; this comparison merits further research.
- Enforcement needs to be focused on shale gas effects with the highest risk (e.g., subsurface releases) rather than on minor or readily evident violations (e.g., inadequate fencing, misplaced signage).
- Regulations need to be set up to match as closely as possible the stiffness of penalties to the relative degree of environmental impact.
- Enforcement records indicate that surface incidents are important in relation to underground occurrences; this may in part be because they are easier to observe and

report by inspectors; some states may need to turn inspection and enforcement efforts toward higher-risk incidents, both underground and at the surface.

- The tendency of the media to focus on the fracturing stage of shale gas development may not be justified based on the violations information found in the four states evaluated.
- Strong focus in the media on impacts on groundwater resources could pull attention away from potentially higher risks of surface incidents.

3 News Coverage and Public Perceptions of Hydraulic Fracturing

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1 Introduction and Overview

This project locates and documents popular media coverage of shale gas production and extraction. Further, this project seeks to assess knowledge of and attitudes toward shale gas production and extraction among residents of the Barnett shale area. The result of this two-pronged effort allows researchers to isolate potential links between media coverage and public knowledge and attitudes in the Barnett shale. This assessment will allow for recommendations for future public communication and diffusion of research in the Barnett shale region, but also will serve as a case study with implications beyond this region.

In sum, this project consists of two phases: 1) a content analysis of media coverage of shale gas production and extraction in news articles and stories that would have been available to audiences within three large US-based shales – Barnett, Marcellus, and Haynesville – during a 12-month period and, 2) a shale gas production and extraction "knowledge assessment" survey of 1,473 respondents currently living in the 26 counties that cover or touch on the Barnett shale.

Looking at phase one, the content analysis, media coverage from June 2010 through June 2011 was examined. To locate the media coverage, popular national and metropolitan coverage that was available to people living in the Barnett, Marcellus, and Haynesville shales was searched. Our selection of media within these areas, as well as national media is detailed below.

Once media were located nationally and within the above shale areas, a list of key words was compiled by the Energy Institute research team to aid us in searching for articles relevant to hydraulic fracturing (see Appendix A for keywords). Search results are detailed below.

The second phase of this project, the literacy assessment, determines what the audience knows about hydraulic fracturing. This information is then used to link back to media coverage in phase one. Specifically, looking at the Top 10 keywords searched within the Barnett Shale media, phase one will examine how media coverage influences public understanding of hydraulic fracturing. Moreover, phase two will compare the knowledge and attitude survey results gathered from the Barnett Shale to national data. Additional insights include respondents' media consumption patterns, attitudes about and perceptions of hydraulic fracturing, and behaviors/behavioral intentions related to fracturing (e.g., voting, speaking out publicly,

blogging or writing editorials, contacting politicians, joining protest or support groups, etc.). Among other things, this data will allow for future messaging that is responsive to residents' information needs and concerns.

2 News Coverage Methods

The sampling frame for media coverage extended a year from June 2010 through June 2011. This time period corresponded with duration of the larger Energy Institute project and included the 12 months preceding the collection of Phase Two knowledge and attitude data.

To locate media coverage within this time frame, we used databases of national newspaper stories provided by Lexis-Nexis and Factiva; databases of national television and radio stories provided by Lexis-Nexis; and archives of local metropolitan newspaper and television stories. To identify metropolitan areas of interest, we studied maps of the shale areas and located the nearest metropolitan areas with media outlets. The areas were chosen for the reach of their circulations in the surrounding shale areas. For the Marcellus shale, we located Pittsburgh, Allegheny County, PA; Buffalo, Erie County, NY; Charleston, Kanawha County, WV; Cleveland, Cuyahoga County, OH; Hagerstown, Washington County, MD; and Roanoke, Roanoke County, VA. For the Haynesville shale, we identified Shreveport, Caddo Parish County and for the Barnett[1] shale, we located Dallas, Dallas County; Fortworth, Tarrant County; and Denton County.

Once the media outlets were identified, we searched the databases and archives for stories relevant to "Hydraulic fracturing, or hydraulic fracking, or hydraulic fracing" and any of the key words provided by the Energy Institute team (Appendix A). The EI keyword list was compiled with the assistance of a team of experts from nine colleges at the University of Texas at Austin, including business and engineering. The experts specialized in issues and science related to hydraulic fracturing and shale gas development. The list was developed collaboratively through consensus and repeated review by the team over the course of several months. The final list of keywords was also used in the analysis detailed in the research report drafted by Wiseman's team; thus, there is consistency across EI reports.

Using these keywords as our search terms, we located 999 stories and articles for analysis. To gauge the comprehensiveness of this sample, we compared that number to the number of stories and articles that surfaced with the more general search terms of "hydraulic fracturing, or hydraulic fracking, or hydraulic fracing." These three terms, which captured all mentions of

these very general search terms, generated an additional 1506 stories and articles. Data on these additional articles are available through the EI. Comparing these numbers allows us to say that the keyword list generated by the expert team captured 66% of the overall coverage of hydraulic fracturing, including all mentions of that term, regardless of context, etc.

All articles were assessed for whether or not they referenced any scientific research. Additionally, articles were also coded for tonality. Tonality was coded as primarily negative, primarily positive or primarily neutral. Based on these definitions of negative, positive and neutral, (which are further described below), 48 articles were coded by two graduate research assistants. Percent agreement between the two coders was 80%. After establishing the intercoder agreement, the remaining articles were coded by one of the graduate research assistants who had reached acceptable agreement. Additional information on this variable is detailed below.

2.1 Newspapers

National

Three newspapers were included in the national search: The Wall Street Journal (WSJ), The New York Times (NYT), and USA Today. According to the Audit Bureau of Circulations (ABC, 2011), these are the three most circulated newspapers in the United States. The WSJ has a daily circulation of more than 2 million people and a Sunday circulation of 1.99 million people. USA Today has a daily circulation of 1.8 million, and the NYT has a daily circulation of .9 million and a Sunday circulation of 1.3 million.

Metropolitan

Metropolitan newspapers were identified through the weekday circulation by Designated Market Area (DMA) within each shale area. The top newspapers with the highest circulation in the DMA were included in the search. That is, Dallas Morning News, Denton Record Chronicle, and Fort Worth Star-Telegram for Barnett; Shreveport Times for Haynesville; and Pittsburg Tribune-Review, Pittsburg Post Gazette, Charleston Gazette, Buffalo News, Roanoke Times, and Cleveland Plain Dealer for Marcellus. Circulation data were found with the SRDS (Standard Rate & Data Service) publications database. Of note, our original intention was to include local media within the Barnett shale, however, media archives for this area (which included the counties of Denton, Johnson, Tarrant, Wise, Archer, Bosque, Clay, Comanche, Cooke, Coryell,

Dallas, Eastland, Ellis, Erath, Hamilton, Hill, Hood, Jack, Montague, Palo Pinto, Parker, Shakleford, Somervell, and Stephens) was limited at the local level, and thus not deemed possible given the relatively short timeframe for execution of the media coverage project.

2.2 Television

National level

The following national and cable television networks are included in the search: ABC News, CBS News, CNBC News, CNN, Fox News Network, MSNBC. These media outlets were identified as the major cable and national news providers by the Lexis Nexis database.

Local level

We sought the transcripts of local television networks and radio stations in the Barnett, Haynesville, and Marcellus shales to allow for us to read and search the text generated from the transcripts. However, after an exhaustive search, we determined that local TV networks do not provide the public with transcripts of their news. As a result, we looked only at the online text stories posted on the stations' or networks' local Websites.

2.3 Radio

National and Local level

At the national level, NPR transcripts were searched and analyzed within the keyword list previously defined. At the local level, similar to local TV networks, radio stations do not provide the transcripts of their news. Thus, local radio coverage was not included in our analysis.

2.4 Online

In addition to the online counterparts of news media, we also identified and searched the largest online news portal – Google News. Google analytics and trends were also examined to visualize peaks in online searches for hydraulic fracturing information.

2.5 Defining the Media

The following represents the media population used for all analyses.

- Online search
    - Includes the search of Google online news
- National TV and Radio:
    - Includes the following stations: CNN, CBS, MSNBC, abc, NBC, and NPR
- National Newspapers:
    - Includes the following papers: The New York Times, The Wall Street Journal, and The USA Today
- Marcellus Metropolitan TVs
    - Includes the following metropolitan stations (Those stations are the ones that we could access their news articles online and their search options allow us to look for keywords):
        - Pittsburgh: KDKA (CBS), WPXI (NBC), WQED (PBS), and WTAE (abc)
        - Buffalo: WIVB (CBS), and WKBW (Eyewitness News)
        - Charleston: WCHS (abc),
        - Cleveland: WEWS (abc), WKYC (NBC), WOLO (CBS), and WVIZ (PBS)
- Marcellus Metropolitan Daily Newspapers
    - Includes the following metropolitan newspapers:
        - Pittsburgh: Pittsburgh Post Gazette and Pittsburgh Tribune-Review
        - Charleston: The Charleston Gazette
        - Buffalo: Buffalo News
        - Roanoke: The Roanoke Times
        - The Cleveland Plain dealer
- Barnett Metropolitan TVs
    - Includes the following metropolitan stations (Those stations are the ones that we could access their news news articles online and their search options allow us to look for keywords):
        - DFW: KTVT (CBS), KXAS (NBC), KDAF (CW), KDFW (FOX), KERA (Public Media for North Texas), WFAA (abc)
- Barnett Metropolitan Daily Newspapers
    - Includes:
        - The Dallas Morning News
        - The Denton Record Chronicle

The Fort-Worth Star-Telegram (yet to be added
- Haynesville Metropolitan TVs
    - Includes:
        - Shreveport: KTBS
- Haynesville Metropolitan Newspapes
    - Includes:
        - The Shreveport Times

3 News Coverage Results

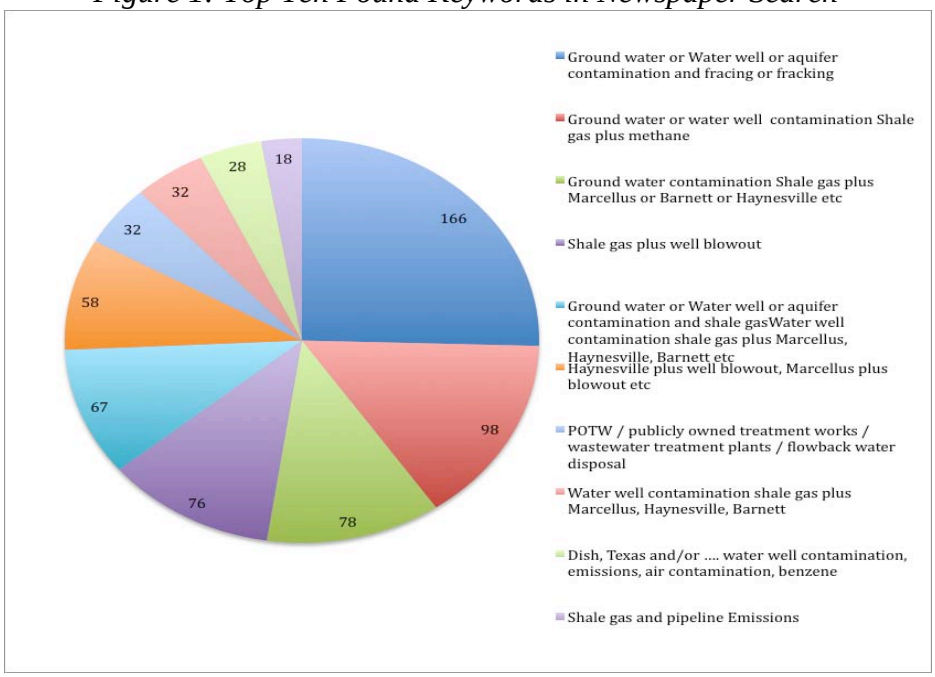
Overall, using the keywords identified by the EI, 999 articles were located; 113 articles were found in national newspapers, 331 in metropolitan newspapers, 74 articles from national television, 150 from metropolitan television, 20 articles from national radio, and 311 from online sources. All results presented will be based on this core set of articles. The frequencies listed below are broken out by keywords and represent how frequently keywords surfaced in articles and stories; furthermore, multiple keywords often surfaced in one article/story.

3.1 Keyword Frequency

Figures 1, 2, and 3 represent the keywords that returned the most searches across the various media.

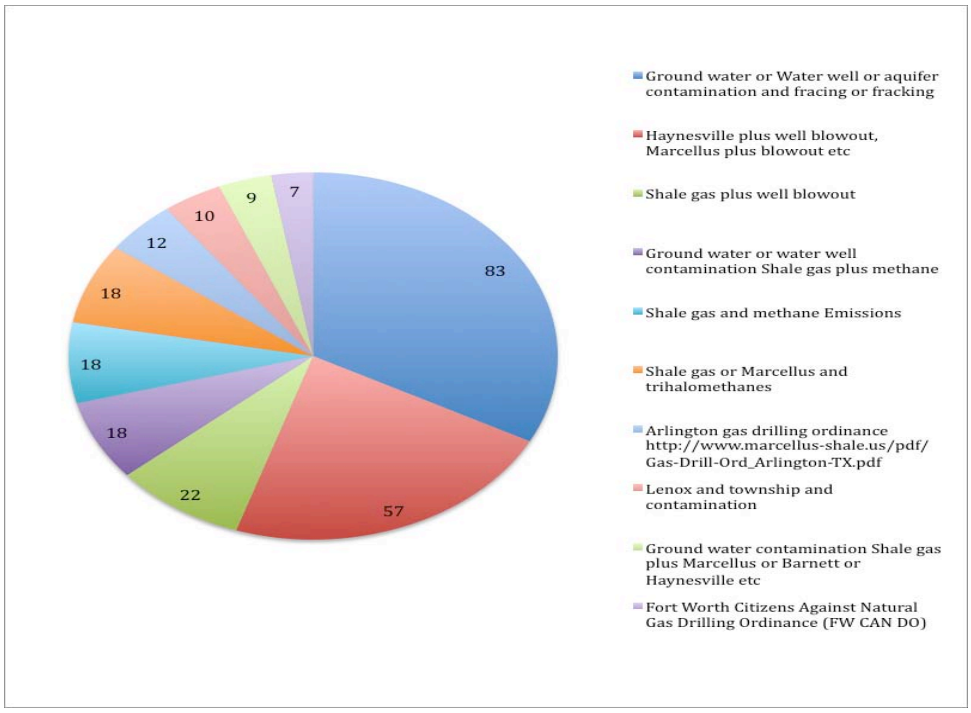
For the Newspaper searches (regional/metropolitan and national) the keyword combination which returned the most results was "Ground water or Water well or aquifer contamination and fracing or fracking" (N = 166), followed by Ground water or water well contamination Shale gas plus methane" (N= 98), and "Ground water contamination Shale gas plus Marcellus or Barnett or Haynesville" (N=78) (Figure 1).

Figure 1: Top Ten Found Keywords in Newspaper Search



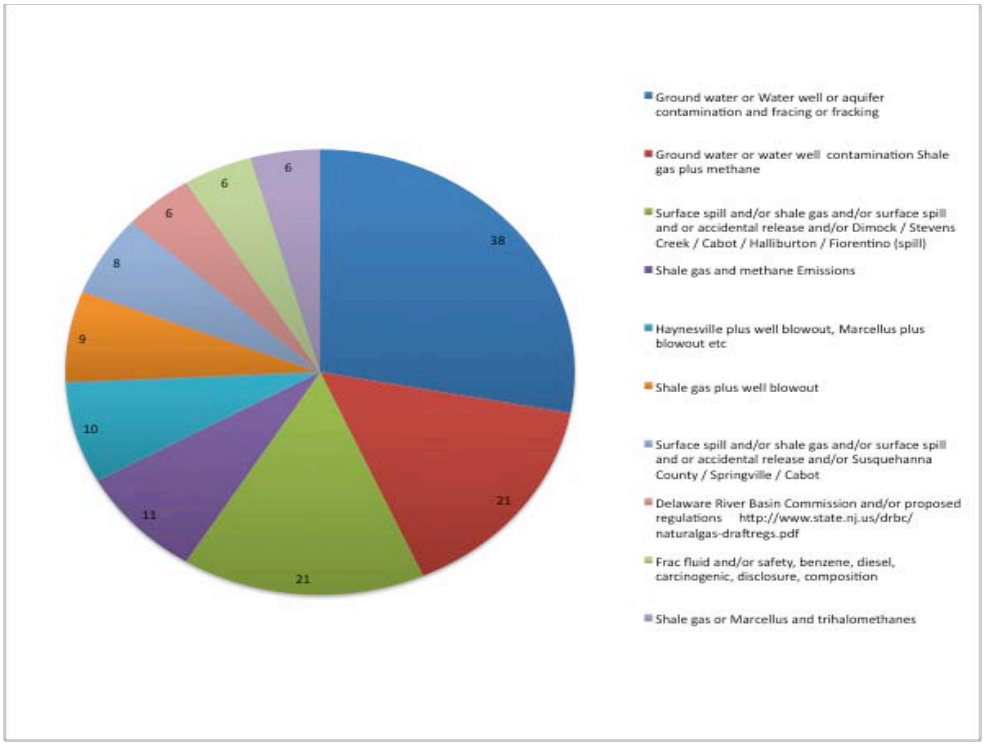
For the online search, the keyword combination which returned the most results is "Ground water or Water well or aquifer contamination and fracing or fracking" (N = 83), followed by "Haynesville plus well blowout", "Marcellus plus blowout" (N= 57), and "Shale gas plus well blowout" (N=22) (Figure 2).

Figure 2: Top Ten Found Keywords in Online Search



For the television and radio searches (regional/metropolitan and national), the keyword combination which returned the most results is "Ground water or Water well or aquifer contamination and fracing and fracking" (N = 38), followed by "Ground water or water well contamination Shale gas plus methane" (N= 21) and "Surface spill and/or shale gas and/or surface spill and or accidental release and/or Dimock / Stevens Creek / Cabot / Halliburton / Fiorentino (spill)" (N=21) (Figure 3).

Figure 3: Top Ten Found Keywords in TV and Radio Searches



3.2 Tonality of Media

As described above, all articles were coded for tonality. Articles covering aspects of hydraulic fracturing associated with negative outcomes (such as pollution, explosions, accidents, explosions, etc.) were coded as "negative." Articles covering aspects of hydraulic fracturing associated with positive outcomes (such as economic benefits, energy availability, etc.) were coded as positive. Finally, when an article was balanced (i.e., presenting both positive and negative outcomes), it was coded neutral.

As shown, the majority of media articles have a negative tonality across the different types of media examined (Newspapers, Online, and TV and radio) (Figures 4, 5, 6a, and 6b).

For newspapers, of the 444 articles found, 288 (65%) were negative, 103 (23%) were neutral, and 53 (12%) were positive. As for the online articles, of the 311 articles found, 197 (63%) were categorized as negative, 92 (30%) were neutral, and only 22 (7%) positive. As for TV, of the 224 retrieved articles, 152 (68%) were negative, 55 (25%) were neutral, and only 17 (8%) were

positive. As for radio, of the 20 articles retrieved, 19 (95%) were negative and 1 (5%) was neutral.

Figure 4: Tonality of Newspaper Searches

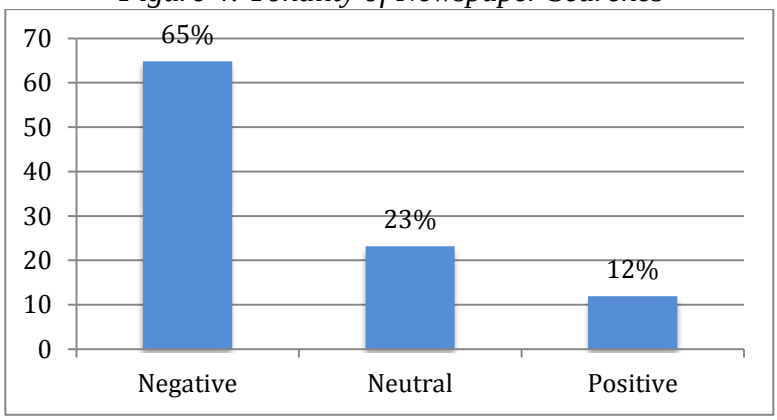


Figure 5: Tonality of Online Searches

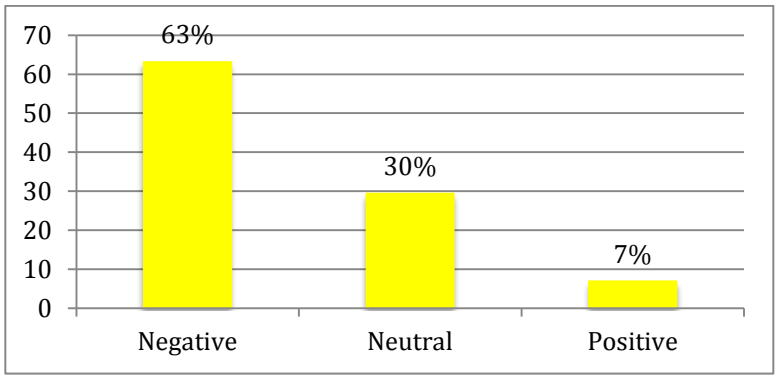


Figure 6a: Tonality of TV Searches

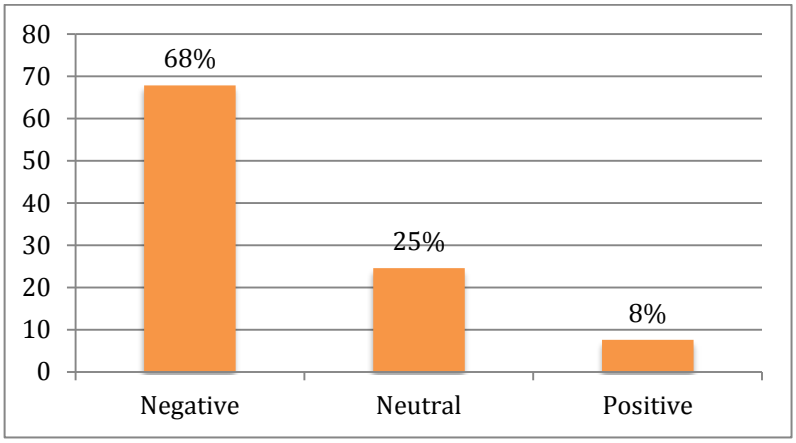
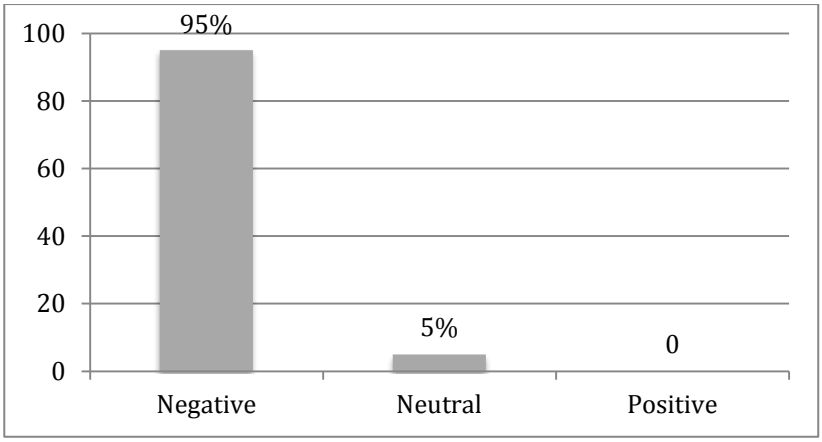


Figure 6b: Tonality of Radio Searches



Tables 1 and 2 represent the tonality of articles by media outlet. Table 1a shows that of the 113 articles found in national papers, 72 are negative, 28 neutral and only 13 positive. Table 1b shows that of the 331 metropolitan newspapers in the three shales, 216 are negative, and only 75 are neutral and 40 are positive. Table 2a shows that of the 74 articles found on national television, 48 are negative, 14 are neutral, and 13 are positive. Similarly, with metropolitan televisions, table 2b shows that 105 of the 150 articles retrieved are negative while only 41 are neutral and 4 are positive.

Table 1a: Tonality of National Newspapers

Tonality	NYT	WSJ	USA Today	**National**
Negative	39	24	9	**72**
Neutral	11	14	3	**28**
Positive	9	3	1	**13**
Total	**59**	**41**	**13**	**113**

Table 1b: Tonality of Metropolitan Newspapers by Shale

Tonality	Haynesville	Marcellus	Barnett	Total
Negative	2	159	55	**216**
Neutral	11	60	4	**75**
Positive	11	18	11	**40**
Total	**24**	**237**	**70**	**331**

Table 2a: Tonality of National Television

Tonality by media, region, scale	**National TVs**							
	ABC	**CBS**	**CNBC**	**CNN**	**FOX**	**MSNBC**	**NBC**	**Total**
Negative	0	4	0	37	0	6	0	**47**
Neutral	0	0	0	8	5	0	1	**14**
Positive	0	6	1	4	2	0	0	**13**
Total	**0**	**10**	**1**	**49**	**7**	**6**	**1**	**74**

Table 2b: Tonality of Metropolitan Television by Shale

Tonality	Haynesville	Marcellus	Barnett	Total
Negative	0	49	56	**105**
Neutral	4	13	24	**41**
Positive	0	4	0	**4**
Total	**4**	**66**	**80**	**150**

3.3 Reference to Scientific Research in Media

Few articles referenced scientific research conducted on the topic of hydraulic fracturing (Figures 7, 8, 9a, and 9b). For newspapers, of the 444 articles found, 362 (82%) had no reference to research. As for the online articles, of the 311 articles found, 207 (67%) had no reference to research. Finally, of the 224 retrieved articles from television, 169 (75%) had no reference to research, and of the 20 articles retrieved from radio, 17 (85%) had no reference to research.

Figure 7: Reference to Research in Newspaper Searches

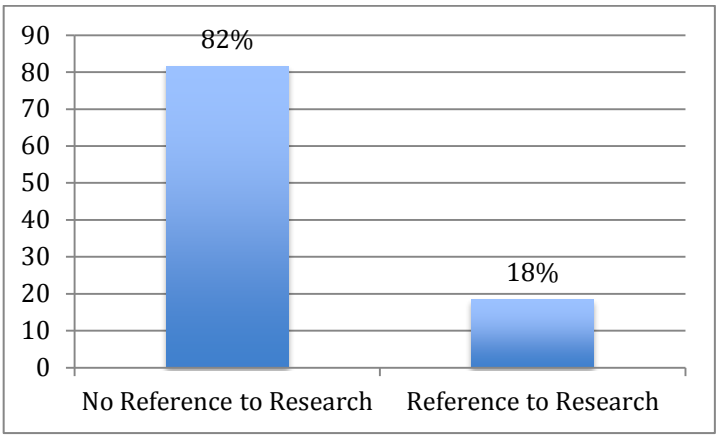


Figure 8: Reference to Research in Online Searches

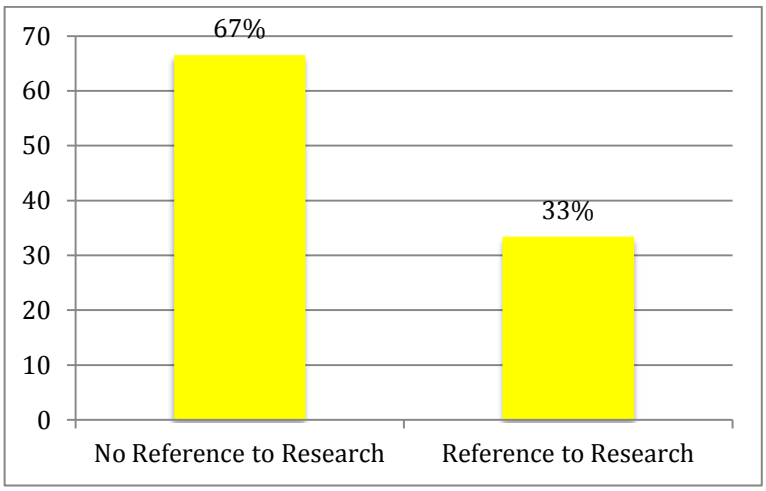


Figure 9a: Reference to Research in TV Searches

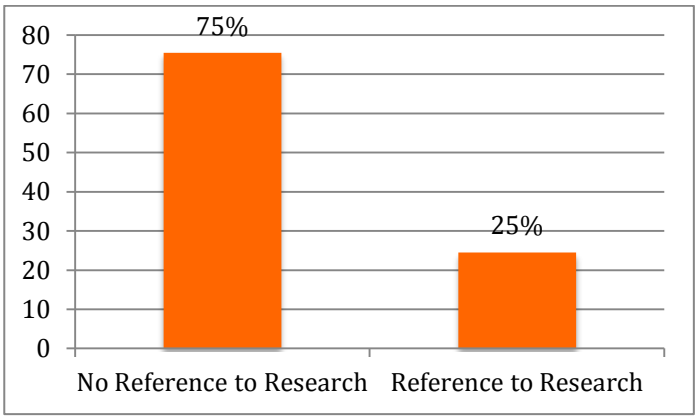
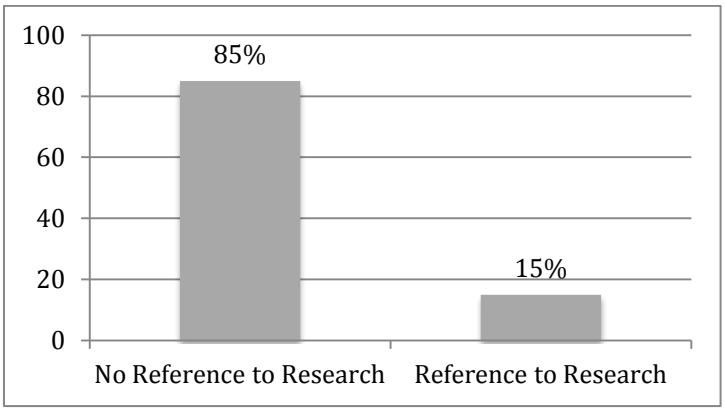


Figure 9b: Reference to Research in Radio Searches



Tables 3 and 4 represent the presence of scientific research in articles related to hydraulic fracturing by media outlet. Table 3a shows that 109 of the 113 articles found in national newspapers don't include any reference to research, while only 4 include a reference to research across all three national newspaper outlets. Also, table 3b shows that for metropolitan newspapers, only 78 articles have reference to research, while 253 don't. Table 4a shows that 56 of the articles found in national televisions don't include any reference to scientific research, and only 18 had reference to scientific research related to hydraulic fracturing. Similarly, for metropolitan televisions, table 4b shows that 114 of the 150 found articles have no reference to research.

Table 3a: National Newspaper Reference to Research

	NYT	WSJ	USA Today	**National**
No	58	39	12	**109**
Yes	1	2	1	**4**
Total	**59**	**41**	**13**	**113**

Table 3b: Metropolitan Newspaper Reference to Research

	Haynesville	Marcellus	Barnett	Total
No	7	204	42	**253**
Yes	17	33	28	**78**
Total	**24**	**237**	**70**	**331**

Table 4a: National Television Reference to Research

	National TVs							
	ABC	**CBS**	**CNBC**	**CNN**	**FOX**	**MSNBC**	**NBC**	**Total**
No	0	10	1	35	6	3	1	**56**
Yes	0	0	0	14	1	3	0	**18**
Total	**0**	**10**	**1**	**49**	**7**	**6**	**1**	**74**

Table 4b: Metropolitan Television Reference to Research

	Haynesville	Marcellus	Barnett	Total
No	4	53	57	**114**
Yes	0	13	23	**36**
Total	**4**	**66**	**80**	**150**

3.4 News Coverage Conclusions

Our results suggest that news coverage on hydraulic fracturing, within the scope of the keyword combinations examined, focused more on the negative outcomes associated with hydraulic fracturing. Reflecting on this, it helps to consider that, across all media, environmental issues such as ground water contamination dominated the narrative; therefore, most articles and stories were coded as negative in tonality (as a result of the focus on contamination). For example, 65% of the stories on ground water contamination (top keyword combination: *Ground water or Water well or aquifer contamination and fracing and fracking*).

Furthermore, the coverage tended not to include scientific research and discovery.

This narrative mainly played out in the New York Times and Wall Street Journal, both of which covered issues related to the potential negative outcomes of fracturing and rarely referenced scientific research. The television narrative was carried by CNN. As with newspaper coverage, over 70% of the coverage surrounded negative issues and approximately 30% referenced scientific research on CNN. Also of note, while CBS carried the second largest number of stories nationally on hydraulic fracturing, they never reported any scientific research in their coverage.

It is important to note a few limitations with the overall media content analysis component. First, the keywords examined only touched on a portion of the articles related to hydraulic fracturing. Across all media under examination, over 1500 documented articles were excluded from the present analysis. This exclusion maintained consistency with other EI reports, but also allowed us to focus on coverage relevant to the three shales of interest. For example, an article was excluded if it was not speaking within the context of Barnett, Marcellus, and Haynesville shales. These excluded articles are included, however, in the data files on record with the EI. Second, due to the lack of access to historical records kept by some media (i.e., smaller local media outlets), the media content covered locally only represents those outlets that made their coverage available electronically (i.e., through transcripts, etc.) for the year under investigation.

Recommendations for future research are as follows. Additional research on the scope of news coverage of hydraulic fracturing will be well-served by building on the EI keywords to maximize the percentage of overall available coverage sampled with those keywords. Furthermore, additional work could be done on the tonality coding scheme. For example, research could

explore the sources of these tonal references. Coding for the tone of news content is notoriously difficult among researchers who practice content analysis. Another area that deserves more attention is the lack of scientific research and discovery found in the articles analyzed. This finding could be further contextualized with a review of the literature on content analysis of science-related news. For example, a review of health coverage by Malone, Boyd and Bero (2000) suggests that media coverage of health issues tends to cover moral issues over the science. This trend needs to be further explored. Finally, because of limitations in online or database access to local news archives, researchers in pursuit of a keener focus on local coverage will need to budget for the difficulties associated with traveling to the local media outlets to search physical archives for any coverage of interest.

4 Public Perceptions Methods

Data were collected from 1,473 respondents who are currently living in the 26 counties that are considered core or noncore counties of the Barnett shale. Included counties were: Denton, Johnson, Tarrant, and Wise (the core counties), and Archer, Bosque, Clay, Comanche, Cooke, Coryell, Dallas, Eastland, Ellis, Erath, Hamilton, Hill, Hood, Jack, Montague, Palo Pinto, Parker, Shakleford, Somervell, Stephens, Young, and Collin. All participants were part of an opt-in online research panel managed by Research Now. The sample was quota-based and thus, was only long enough (5 days) to collect the requested 1,500 participants.

Sixty-three percent of our respondents were female and 37% were male. The average age of the sample was 49 years old. Turning to education, 7% earned a high school degree, 20% have some college education, 9% have a 2-year degree, 37% have a college degree, and 27% have a Masters, PhD, or a professional degree. Twenty eight percent of the respondents earned $50,000 or less annually, 43% earned between $50,000 and $100,000, and 29% earned more than $100,000. A s for political affiliations, 41% of the respondents are republicans, 25% are democrats, and 34% identified themselves as independents. Also, 85% of our respondents identified themselves as Caucasian.

Looking to potential relationships with the oil and gas industry, 17% of the respondents have land currently leased to gas industry operators. And, only 2% of the respondents have a part-time or full-time employment related to hydraulic fracturing.

5 Public Perceptions Results

5.1 Attitude toward Hydraulic Fracturing

A semantic differential attitudinal scale was used to understand the general attitude toward hydraulic fracturing. As presented in Table 5, while many think hydraulic fracturing is productive, wise, important, valuable, and beneficial, they also think it could be bad for the environment. These attitudinal differences displayed throughout Table 5 are very representative of the complexity surrounding the topic of hydraulic fracturing. Those results suggest a certain degree of ambiguity in people's attitudinal positions. This indicates that most people have not formed their positions on h ydraulic fracturing yet, which is important to be taken into consideration when formulating the media messages targeting them.

5.2 Knowledge of Hydraulic Fracturing

Overall, 27 questions developed by the Energy Institute research team were asked regarding the process, regulation, and cost-benefit relationship of hydraulic fracturing (Charts 1 to 27). As with many science related topics, while many living in the Barnett Shale area have some general knowledge about the process of hydraulic fracturing, they tend to lack in their understanding of regulation and the cost-benefit relationship of production. Here, data trends suggest that most overestimate the level of hydraulic fracturing regulation. For example, 71% were not aware that the Railroad Commission (RRC) does not regulate how close a gas well can be drilled to a residential property (Chart 18). Moreover, although the RCC does not regulate liners and drilling pits, 56% thought they did regulate specific requirements (Chart 19). Also, 75% did not know the state of Texas lacks standards for determining the locations, shapes, and sizes of the drilling rigs (Chart 20).

Looking at the resources used and gained through hydraulic fracturing, data indicated that many respondents overestimate annual water consumption for shale gas usage (i.e., 76% overestimate, see Chart 24), and underestimate (75%) the amount of electricity generated from natural gas in 2010 (Chart 26).

Table 5: Hydraulic fracturing is (percentage):

	1	2	3	4	5	6	7	
Safe	4%	9%	14%	48%	12%	7%	5%	**Unsafe**
Good for the economy	12%	17%	22%	41%	4%	2%	2%	**Bad for the economy**
Good for the environment	3%	5%	11%	44%	15%	12%	10%	**Bad for the environment**
Important for energy security in the US	15%	18%	17%	40%	4%	3%	2%	**Unimportant for the energy security in the US**
Positive	7%	10%	14%	48%	10%	6%	4%	**Negative**
Useful	13%	17%	24%	39%	4%	1%	2%	**Useless**
Important	12%	16%	22%	43%	4%	2%	1%	**Not important**
Effective	11%	17%	20%	43%	5%	2%	2%	**Ineffective**
Valuable	11%	18%	20%	44%	3%	1%	2%	**Worthless**
Good	7%	10%	16%	48%	9%	6%	4%	**Bad**
Beneficial	7%	9%	14%	43%	13%	8%	6%	**Harmful**
Wise	7%	11%	16%	54%	6%	3%	4%	**Foolish**
Productive	11%	18%	22%	43%	3%	1%	2%	**Unproductive**
Helpful	9%	13%	18%	49%	6%	3%	3%	**Unhelpful**

To this end, most generally understand the process of fracturing (e.g., Charts 1, 2, 5 and 9) and the gas development surrounding the fracturing of wells (Chart 3). However, the scope (Chart 4) and technical aspects to fracturing are generally less understood. For example, 55% did not accurately estimate the depth of wells being drilled for hydraulic fracturing (Chart 6), 49% were unaware of proppants (Chart 7), and 42% overestimated the scientific evidence surrounding the issue of hydraulic fracturing and water contamination.

Below, we have included all knowledge questions relating to hydraulic fracturing. *We have highlighted the correct answers to each question in red.*

Chart 1. Hydraulic fracturing is the process of producing a "fracture" in:

Answer		Response	%
The underground soil layer		103	7%
The topsoil		36	2%
An old mine		15	1%
The underground rock layer		1,298	89%
Total		1,452	100%

Chart 2. In general:

Answer		Response	%
There is a consensus that hydraulic fracturing is safe for the environment.		200	14%
There is a consensus that hydraulic fracturing is dangerous and harmful to the environment.		152	10%
Some scientists and environmental groups claim hydraulic fracturing is dangerous and should be banned but the industry insists it is a safe technology.		1,042	72%
The industry insists that hydraulic fracturing is dangerous and should be banned, but scientists and environmental groups think it is a safe technology.		56	4%
Total		1,450	100%

Chart 3. More than three quarters of the hydraulic fracturing wells used in the United States produce:

Answer		Response	%
Oil		216	15%
Gas		1,172	81%
Coal		31	2%
Water		34	2%
Total		1,453	100%

Chart 4: Nearly all of the natural gas wells in the United States use hydraulic fracturing.

Answer		Response	%
True		599	42%
False		841	58%
Total		1,440	100%

Chart 5: Hydraulic fracturing requires _____ to retrieve natural gas trapped under the earth's surface.

Answer		Response	%
Hammering solid rock underground		330	23%
Injecting fluid underground		1,022	70%
Extracting soil underground		85	6%
Freezing underground water supplies		15	1%
Total		1,452	100%

Chart 6: Hydraulic fracturing involves drilling under the Earth's surface for

Answer		Response	%
Less than 500 feet		87	6%
1,000-3,000 feet		397	27%
3,000-10,000 feet		648	45%
10,000-50,000 feet		250	17%
More than 50,000 feet		65	4%
Total		1,447	100%

Chart 7: Proppants are

Answer		Response	%
Gaseous material used to induce hydraulic fracturing		419	29%
Compounds used to clean a fracturing site		186	13%
Particles used to hold fractures open after a hydraulic fracturing treatment so that fluids can easily flow along		734	51%
The legal permits required for drilling in fracturing sites		87	6%
Total		1,426	100%

Chart 8: Texas now requires companies to disclose the chemicals they use in hydraulic fracturing.

Answer		Response	%
True		1,026	71%
False		415	29%
Total		1,441	100%

Chart 9: The fracturing fluid is used to induce a hydraulic fracture by:

Answer		Response	%
Over flooding the ground level surface area		48	3%
Displacing ground water		128	9%
Applying pressure to produce a crack in the natural rock formation		1,213	84%
Washing out the soil to release pressure		61	4%
Total		1,450	100%

Chart 10: During the fracturing process, if fracturing fluid seeps from the fracture channel into the surrounding permeable rock, this is called:

Answer		Response	%
Fracture Gradient		167	12%
Leak off		378	26%
Frack Seepage		837	58%
Natural Gas		49	3%
Total		1,431	100%

Chart 11: The Ground Water Protection Council, Natural Resources Defense Council, FW CAN DO, and PARCHED are:

Answer		Response	%
Gas drilling companies		71	5%
Government agencies		155	11%
Environmental Groups		1,192	82%
TV shows		27	2%
Total		1,445	100%

Chart 12: There is considerable scientific evidence that hydraulic fracturing has resulted in the contamination of water.

Answer		Response	%
True		613	42%
False		831	58%
Total		1,444	100%

Chart 13: Well blowouts occur:

Answer		Response	%
Frequently in drilling wells		88	6%
When the drilling well explodes		274	19%
When drilling fluids escape from the top of the wellbore under high pressure		1,049	73%
When the weather conditions are bad		23	2%
Total		1,434	100%

Chart 14: In general, blowouts that occur during the drilling process have an environmental impact similar to surface spills.

Answer		Response	%
True		1,032	72%
False		402	28%
Total		1,434	100%

Chart 15: In the Barnett shale, there has been:

Answer		Response	%
No blowouts		318	22%
20 or less blowouts		772	54%
20-40 blowouts		218	15%
40 or more blowouts		113	8%
Total		1,421	100%

Chart 16: The Barnett shale area extends over:

Answer		Response	%
50 square miles		68	5%
500 square miles		202	14%
1,000 square miles		318	22%
5,000 square miles		437	30%
15,000 square miles		409	29%
Total		1,434	100%

Chart 17: Drilling activity in the Barnett shale is regulated by the Railroad Commission of Texas (RRC) and:

Answer		Response	%
Texas Department of State Health Services (DSHS)		51	4%
Texas Commission on Environmental Quality (TCEQ)		1,046	73%
Texas Department of Transportation		138	10%
Texas Department of Agriculture		199	14%
Total		1,434	100%

Chart 18: The Railroad Commission regulates how close a gas well can be drilled to a residential property.

#	Answer		Response	%
1	True		1,024	71%
2	False		419	29%
	Total		1,443	100%

Chart 19: The Railroad Commission rules do not include specific requirements for liners in drilling pits.

#	Answer		Response	%
1	True		625	44%
2	False		801	56%
	Total		1,426	100%

Chart 20: In Texas, there are standards for determining the locations, shapes and sizes of the drilling rigs.

#	Answer		Response	%
1	True		1,074	75%
2	False		350	25%
	Total		1,424	100%

Chart 21: Texas law allows drillers to use as much of the surface as necessary to explore, drill and produce the minerals from a property.

#	Answer		Response	%
1	True		585	41%
2	False		849	59%
	Total		1,434	100%

Chart 22: Texas Railroad Commission has no authority over the impact on property value as a result of drilling activities on properties.

#	Answer		Response	%
1	True		912	63%
2	False		526	37%
	Total		1,438	100%

Chart 23: In Texas, an oil or gas operator is required to perform an environmental study before drilling.

#	Answer		Response	%
1	True		1,090	76%
2	False		353	24%
	Total		1,443	100%

Chart 24: In the Barnet shale area, the annual water consumption for shale gas usage is:

#	Answer		Response	%
1	Less than 2%		334	24%
2	2-4%		406	29%
3	4-6%		342	24%
4	>6%		334	24%
	Total		1,416	100%

Chart 25: In Texas' Barnett shale, the number of active/producing horizontal wells increased from fewer than 400 in 2004 to more than _____ during 2010.

#	Answer		Response	%
1	1,000		516	36%
2	10,000		673	47%
3	20,000		180	13%
4	30,000		54	4%
	Total		1,423	100%

Chart 26: In 2010, the percentage of electricity in Texas produced from natural gas was:

#	Answer		Response	%
1	less than 18%		566	40%
2	28%		492	35%
3	38%		277	19%
4	48%		90	6%
	Total		1,425	100%

Chart 27: In 2010, US shale gas production was _____ of total US natural gas production.

#	Answer		Response	%
1	less than 3%		375	26%
2	13%		542	38%
3	23%		325	23%
4	33%		180	13%
	Total		1,422	100%

5.3 Linkage to Phase One Media Coverage

Several knowledge questions included in this survey where based on the top 10 ke yword searches identified in the media search completed and explicated in Phase One (above) of this study (Figures 1, 2, and 3). More specifically, given that the survey was only assessed residents within the Barnett Shale, the survey conducted in Phase Two used the top 10 keyword searches identified specifically in the Barnett shale media coverage (Table 6 and Table 7). For instance, we asked respondents about their knowledge ground water contamination, air contamination, drilling regulations, well blowouts, and other topics covered by the Barnett Shale media (i.e., newspapers and televisions).

From Barnett Shale resident assessment, it is clear that respondents are generally more knowledgeable about key issues covered in the media. For example, environmental issues such as ground contamination were relatively frequent in media coverage. Consequently, knowledge of policy issues related to contamination such as the disclosure of chemicals used during fracturing (see Chart 8) and active groups affiliated with ground water issues (see Chart 11) was relatively high. Additionally, topics related to well blowouts were also high in media coverage (see Table 6 and 7) and in knowledge. To this end, 73% correctly identified when well blowouts occur during the fracturing process (Chart 13), 72% correctly evaluated the impact of well blowouts in comparison to surface spills (Chart 14), and finally, as shown in Chart 15, 54% understand the frequency that well blowouts have occurred across the Barnett Shale. Charts 24 through 27 provide further evidence that coverage influences knowledge. Here, consistent with

the lack of media coverage on positive outcomes associated with fracturing, knowledge of potentially positive associations is relatively low.

The evidence that media coverage on hydraulic fracturing does influence knowledge acquisition should allow policy makers to better understand how to reach relevant publics on such a complicated topic. It also should alert policy makers to the fact that much of the information being reported is not based on, or at least referencing, scientific research and in many cases reports on the negative consequences associated with hydraulic fracturing. If the public is going to be able to accurately understand the impact, positive and negative, that fracturing has on society, it is imperative that media coverage represents the breadth of issues associated.

Table 6: Top Barnett Newspaper Media Search

Keyword	Frequency
Dish, Texas and/or water well contamination, emissions, air contamination, benzene	12
Ground water or Water well or aquifer contamination and fracing or fracking	9
Shale gas and pipeline Emissions	8
Fort Worth gas drilling ordinance/ gas drilling task force	5
Pipeline Leaks together with Barnett Shale or Haynesville etc	4
Water well contamination plus arsenic, and/or chromium,	4
Earthworks OGAP Oil and Gas Accountability Project	3
Ground water or water well contamination Shale gas plus methane	3
Haynesville plus well blowout, Marcellus plus blowout etc	3
Flow-back water and shale gas and/or Marcellus, Barnett, Haynesville etc	2
Salt water injection well or Disposal well together with environmental contamination or problem, well integrity problem, cases pressure, groundwater contamination	2
Shale gas and methane Emissions	2
TCEQ air quality study	2
Water well contamination shale gas plus Marcellus, Haynesville, Barnett	2

Table 7: Top Barnett TV Media Search

Keyword	Frequency
Shale gas and methane Emissions	11
Ground water or water well contamination Shale gas plus methane	9
Shale gas or Marcellus and trihalomethanes	6
Dish, Texas and/or water well contamination, emissions, air contamination, benzene	4
Pennsylvania Environmental Council	4
Fort Worth gas drilling ordinance/ gas drilling task force	3
Frac fluid and groundwater contamination	3
Riverkeeper (collects alleged cases of environmental contamination from drilling and fracturing)	3
Shale gas and Ground water or water well contamination and Surface spill and or accidental release Surface spill and/or shale gas and/or surface spill and or accidental release and/or drill pad or pad	3
Shale gas plus well blowout	3
TCEQ air quality study	3

5.4 National Media Comparison to the Barnett Shale

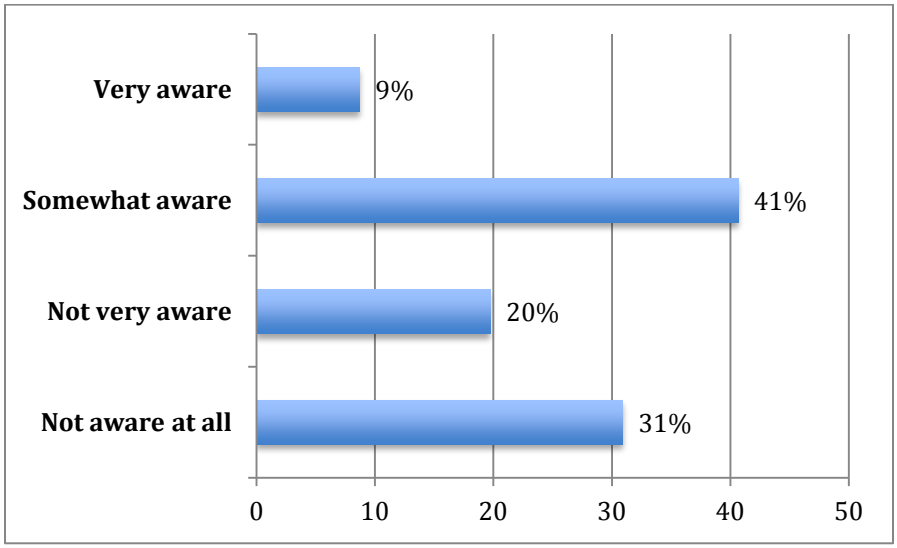
To gain perspective on the perceptions of Barnett shale residents, we have included survey questions included in a national survey conducted for the Civil Society Institute in 2010. These additional questions allow us to compare perceptions of people living in the Barnett shale to nationwide perceptions. In doing so, we will be able to see how media coverage within the Barnett Shale has influenced its residents compared to a national sample.

5.4.1 Awareness of Hydraulic Fracturing

Fifty percent of the respondents from Barnett shale considered themselves to be somewhat aware or very aware of the issue surrounding hydraulic fracturing (Chart 28) compared to 43% found in the national survey.

Chart 28: As of right now, how aware would you say you are about the issue of hydraulic fracturing?

Barnett Shale Survey Results



Looking at the gender trends and awareness of hydraulic fracturing, males surveyed in from the Barnett Shale were more aware of the issue of hydraulic fracturing than the females. Specifically, 64% of males reported being somewhat/very aware of hydraulic fracturing compared to 41% of

the women. Those results are similar to the national survey where males reported more awareness than females (52% vs. 35%).

Politically, Independents in the Barnett shale indicated more awareness on the issue of hydraulic fracturing with 54% reporting very or somewhat awareness. Forty-eight percent of Democrats and 46% of Republicans reported an awareness level of very or somewhat. In the national survey, awareness was relatively similar among different political affiliations, such that 49% of Republicans, 47% of Independents and 39% of Democrats considered themselves aware.

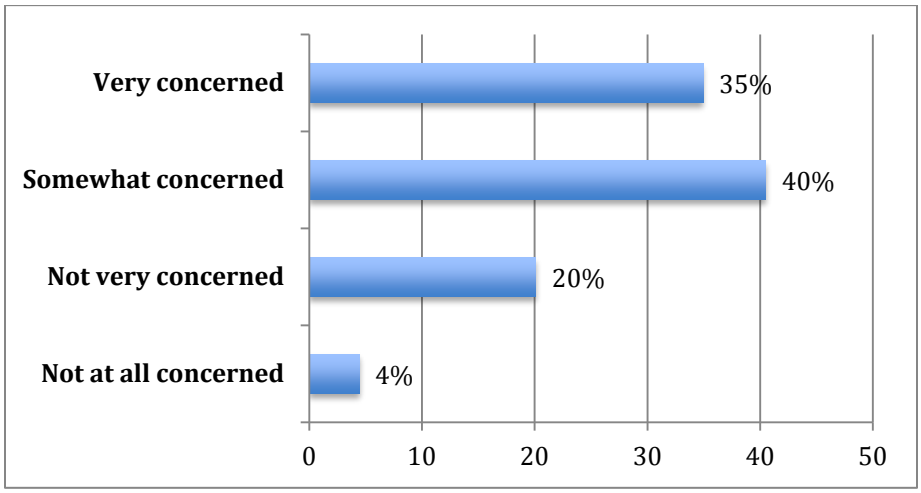
When considering the education level of respondents, Barnett Shale respondents with a college degree or higher education level were more likely (51%) to report a higher knowledge about hydraulic fracturing than people who have a high school degree or less (33%). In the national survey, similar results were noticed such that 51% of those who have a college degree or higher, and 37% of those who have a high school degree or less are aware of hydraulic fracturing.

5.4.2 Concern about Water Quality

In the Barnett Shale, 75% of those who were aware of hydraulic fracturing said they are very/somewhat concerned about the issue of water quality. (Chart 29). This is very close to the percentage found in the national survey (69%) This finding is not surprising given the amount of media coverage the issue of water contamination received across all media.

Chart 29: Still thinking about the natural gas drilling process sometimes referred to as fracking, how concerned are you about this issue as it relates to water quality?

Barnett Shale Survey Results

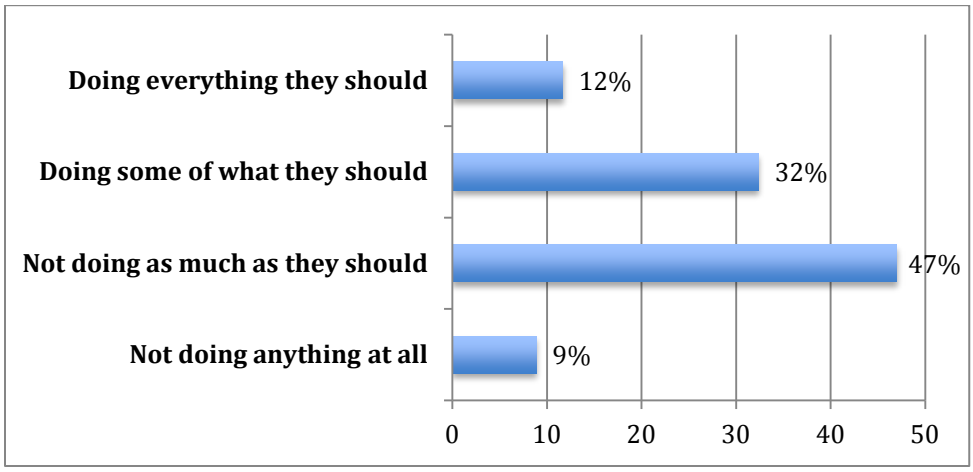


5.4.3 Disclosure of Chemicals used in Hydraulic Fracturing

When questioned what they think of the efforts by state and national officials regarding the disclosure of chemicals used in natural gas drilling, 44% of respondents reporting awareness of hydraulic fracturing in the Barnett Shale said they are doing "everything or some of what they should be doing", (Chart 30) compared to 33% of those reporting awareness in the national survey.

Chart 30: Do you think that state and national officials are doing enough to require disclosure of the chemicals used in natural gas drilling? Would you say they are...

Barnett Shale Survey Results

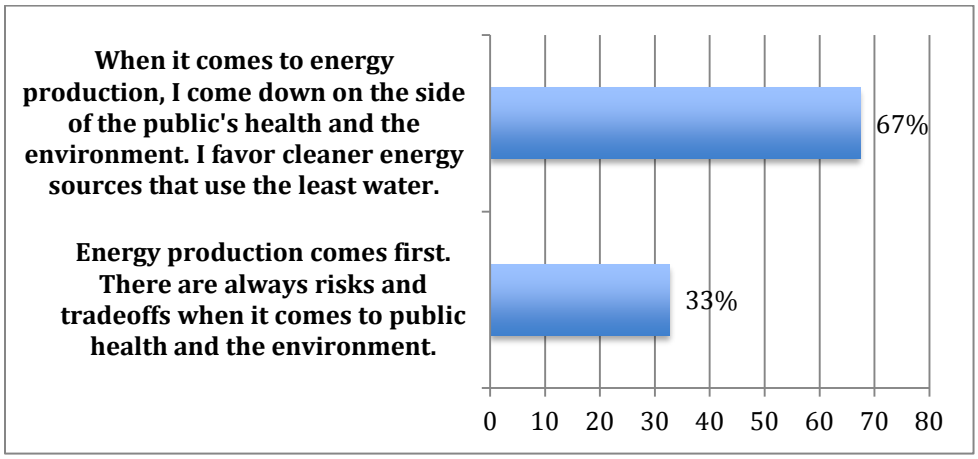


5.4.4 Message to Politicians

Sixty-seven percent of respondents from the Barnett Shale who disclosed awareness of hydraulic fracturing said they favor cleaner energy sources, while 33% said they favor energy production. (Chart 31) At the national level, 72% said they care more about cleaner energy and only 21% said they favor energy production.

Chart 31: If you could speak directly to your member of Congress, your governor or state leader, which of the following statements would you be most likely to make to them?

Barnett Shale Survey

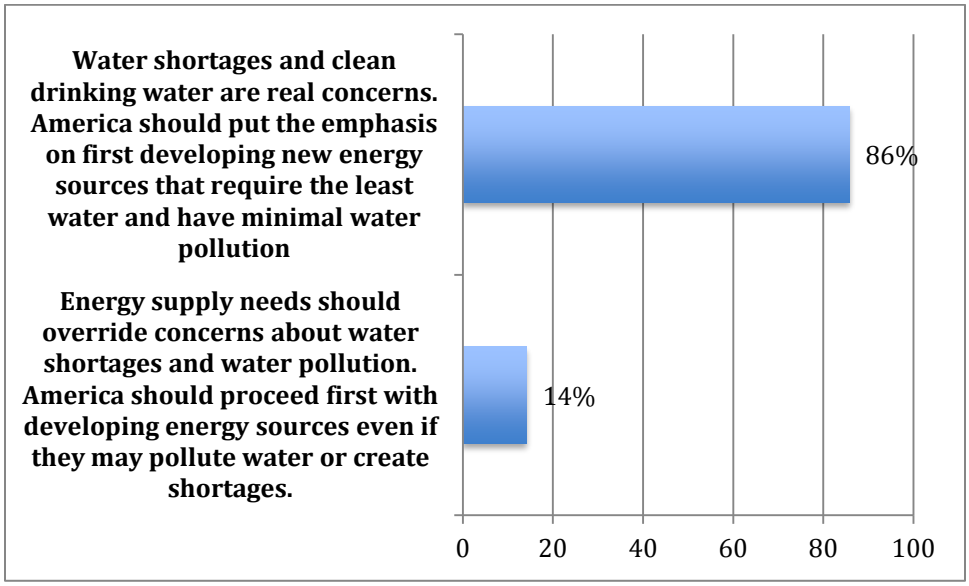


5.4.5 Focus on America's Future Energy Production

Eighty-six percent of those aware of hydraulic fracturing in the Barnett Shale and 81% nationally said America should focus on new energy sources that require the least water and minimal pollution. (Chart 32) Only 14% of those reporting awareness of hydraulic fracturing in the Barnett Shale and 12% nationally said that America should proceed first with developing energy sources even if they may pollute water or create shortages.

Chart 32: Which of the following statements best expresses your view about where America should focus its energy production in the future?

Barnett Shale Survey Results

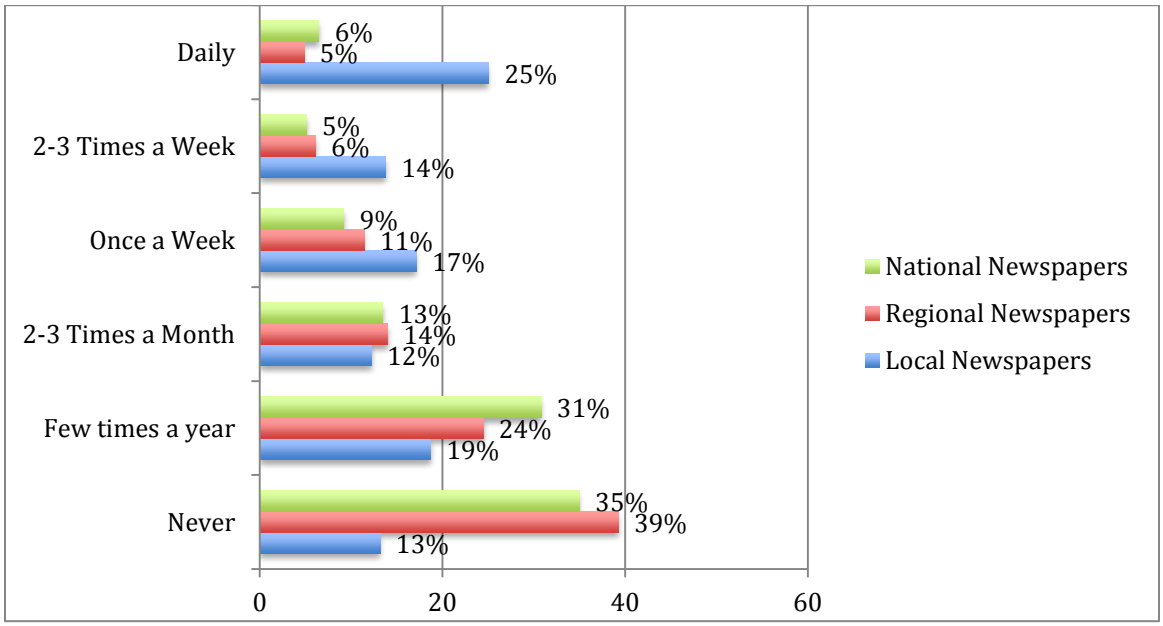


In summary, we have found that communities in the Barnett shale perceive themselves to be more aware of hydraulic fracturing than the national sample. However, they are similar to the national sample in their concerns about water quality and what politicians are doing about the issue. This should alert politicians to the local and national concerns related to hydraulic fracturing and the level of accountability the public holds for policy makers regarding the issue.

5.5 Media Habits

Looking at newspaper use among Barnett Shale residents, data indicate that many no longer read national (35%) or regional (39%) newspapers. Local newspaper, however, seems to have the highest rate of use -daily (25%), 2-3 times a week (14%) and once a week (17%). (Chart 33)

Chart 33: Frequency of newspaper use



Turning to television use, most respondents have indicated they use cable (54%), national network (50%), and local (60%) daily. Conversely, only 17% of respondents never use cable television, 7% never use national television, and only 4% never use local television (Chart 34). Generally speaking, when trying to reach the Barnett Shale population, television should be considered a good media outlet for message delivery.

Similar to newspapers use, magazine use is relatively low. For example, 48% of respondents never or seldom use national magazines. Local magazine use was even lower, with 61% reporting never or seldom use. (Chart 35)

Chart 34: Frequency of television use

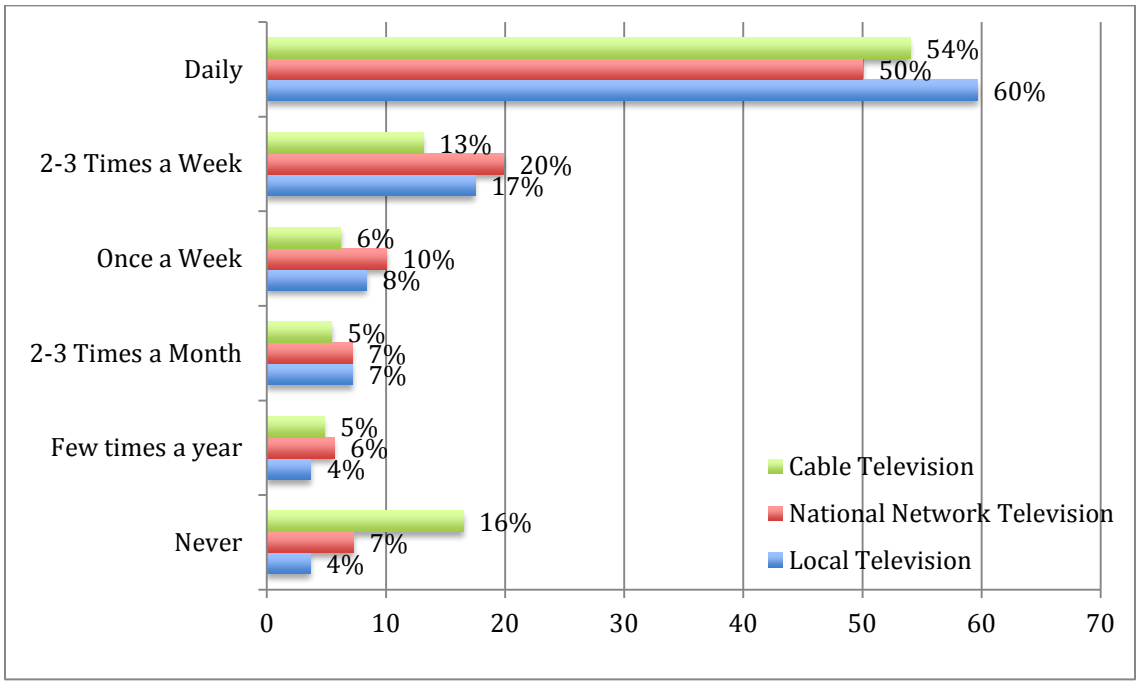
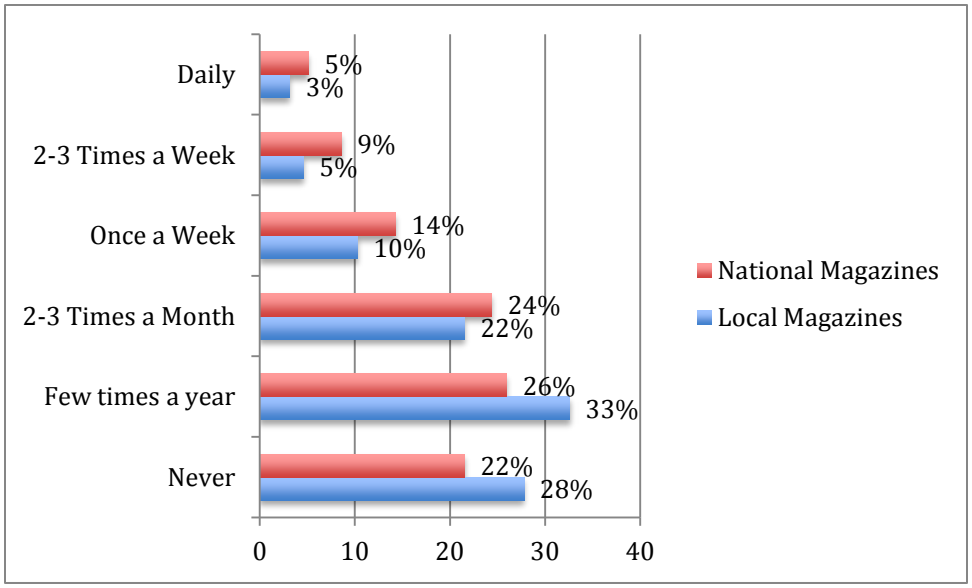
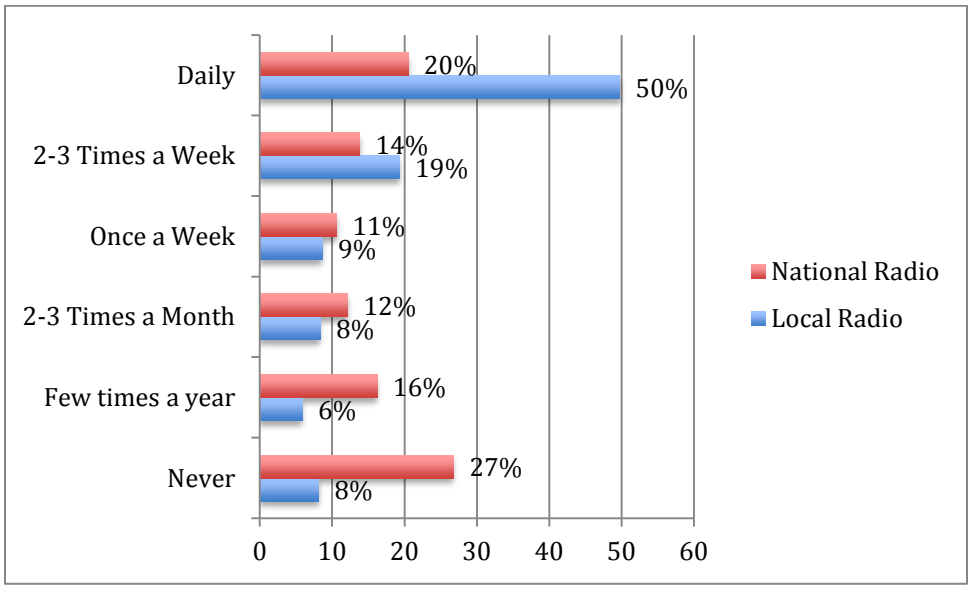


Chart 35: Frequency of magazine use



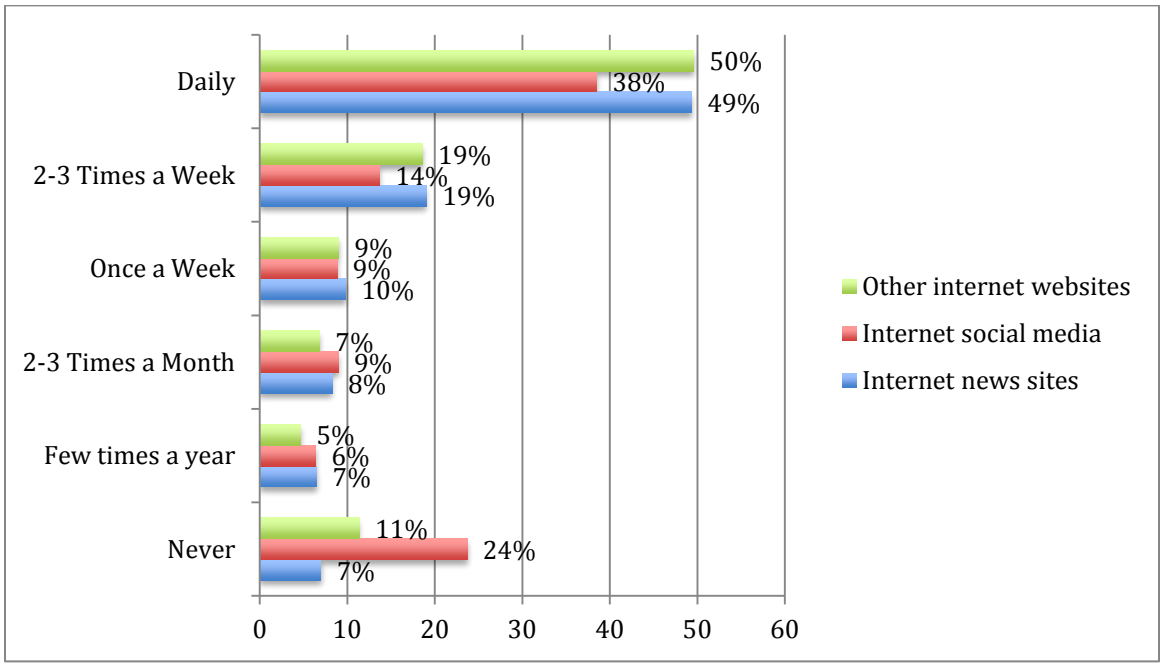
Local radio seems to be a promising media to reach the Barnett Shale residence. Here, 50% of respondents use the local radio on a daily basis, while 21% use national radio daily. Only 8% never use local radio, and 27% never use national radio. (Chart 36)

Chart 36: Frequency of radio use



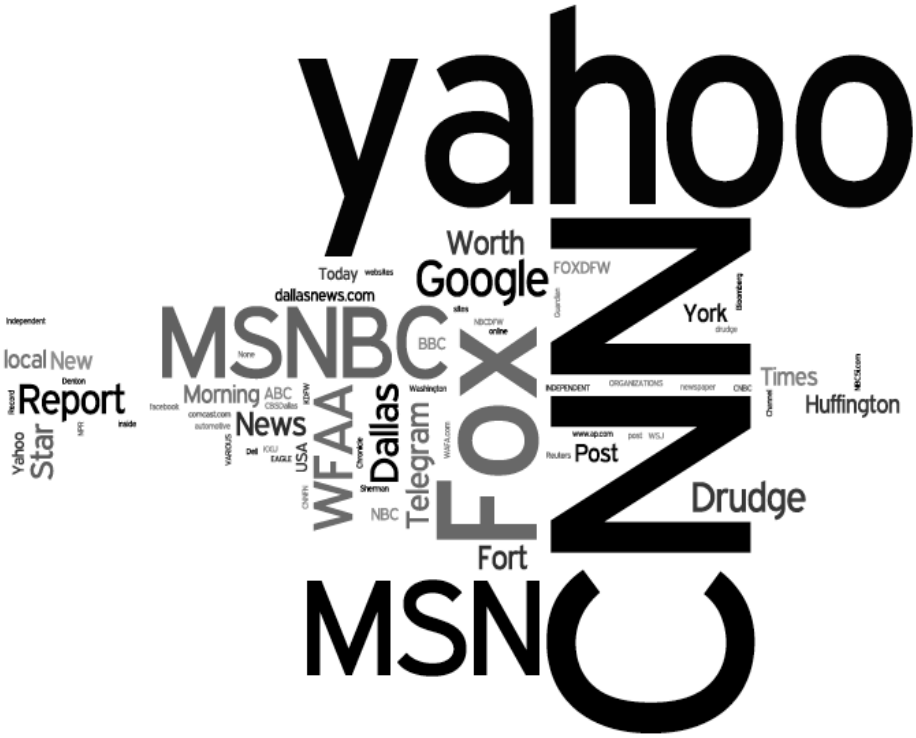
Displaying similar numbers to television, online resources seem to be part of many residents' daily routine. Fifty percent indicated they visit a generic website daily, 39% specifically use social media daily, and 49% use a news website daily. Comparing these numbers to those who never use a generic website (11%), social media (23%) and news website (7%), one can conclude that if placed correctly (i.e., good SEO, SEM, etc.), digital media such as the Internet could represent a good information dissemination platform. (Chart 37)

Chart 37: Frequency of Internet use



Focusing on digital media, online information sources were further explored through an open-ended question. The following represents the magnitude of use within each displayed source among the Barnett Shale population. For example, CNN, MSN, and Yahoo dominated the news use within the digital sphere (Chart 38). Thus, when considering where to reach the Barnett Shale residents online, media strategist are better off place their message on or within the MSN, CNN or Yahoo news sections.

Chart 38: What websites do you use to get your news?



5.6 Commitment to Involvement

Table 8 reports behavioral perceptions toward hydraulic fracturing. As presented, many of the means are close to the midpoint of the scale, thus, suggesting people are either undecided or ambivalent or that they sense two equal view points and aren't sure with which to agree. Regardless, undecided populations can be considered very useful in terms of campaign direction. The lack of polarization within these individuals allows them to be open to developing a viewpoint and thus, is key when considering who to target for knowledge acquisition. Moreover, for several items, it also appears that respondents sense that it is not desirable to get involved (see items 4 and 5). Meaning, respondents are mostly unwilling to participate in any events in support or against hydraulic fracturing. This could be related to their ambiguous attitudes. Consequently, this too could be a direction for campaigning to this audience.

Table 8: Please indicate your agreement or disagreement with the following statements about community efforts (organizing, protesting, calling legislators, petitioning, etc.) (percentages).

	Strongly Disagree	Disagree	Neither Agree nor Disagree	Agree	Strongly Agree
My community will appreciate me taking action when it comes to hydraulic fracturing.	3%	11%	69%	14%	2%
If I participate in events related to hydraulic fracturing, I will feel like I am doing something positive for my community.	2%	9%	56%	30%	2%
Participating in community efforts related to hydraulic fracturing will make me feel good about myself.	4%	13%	60%	20%	2%
People who are important to me think that I should not participate in community efforts related to hydraulic fracturing.	13%	23%	57%	5%	1%
I feel I am under social pressure to participate in community efforts related to hydraulic fracturing.	25%	34%	39%	2%	1%
I will vote for the candidate who takes a stand on hydraulic fracturing.	5%	12%	66%	15%	3%
Participating in community efforts is important to me.	4%	10%	49%	33%	4%
I know how to participate in community efforts related to hydraulic fracturing.	10%	28%	47%	13%	1%
My family expects me to participate in community efforts related to hydraulic fracturing.	24%	33%	40%	3%	1%
I know where to go to get involved in community efforts related to hydraulic fracturing.	15%	30%	41%	13%	1%
If I wanted to, I could participate in community efforts related to hydraulic fracturing.	4%	8%	48%	36%	5%

5.7 Public Perceptions Conclusions

Respondents, in general, seem to have mixed attitudes towards hydraulic fracturing; however, they tend to have more negative than positive perceptions of the fracturing process. For instance, they view it as mostly bad for the environment, unsafe, and harmful. However, when it comes to taking action about hydraulic fracturing, we notice that generally, respondents have no intention to engage in any behavior against or in support of hydraulic fracturing. Moreover, residents of the Barnett shale are generally informed about issues related to hydraulic fracturing; however, they tend to overestimate existing shale gas regulations in Texas.

Compared to a national survey conducted in 2010 by the Civil Society Institute, the Barnett shale respondents report greater awareness of hydraulic fracturing than the national sample. However, they are similarly concerned concern about water quality as a result of hydraulic fracturing and prefer cleaner energy sources. Also, they generally think that policy makers are not doing everything they should to disclose chemicals used in natural gas drilling.

As for the media use of the Barnett shale sample, they read local newspapers, watch national, cable, and local television, listen to local radio, and use the internet almost daily. This provides us with an idea of where to place campaigns to inform the Barnett shale population about hydraulic fracturing.

6 Overall Conclusions

To begin, a key limitation of the study relates to the scope of keywords used for each media. The keyword list used did not turn out all instances of hydraulic fracturing covered. However, the entirety of hydraulic fracturing coverage (i.e., beyond the keywords) is available on the Energy Institute website.

The sample surveyed from the Barnett Shale counties suggest that people are very likely to use local and national media outlets for their news. Specifically, people refer daily to local newspapers (25%), local television networks (60%), regional television networks (60%), national television networks (54%), local radio (50%), and national radio (20%). Online sites are also a major source of news. For instance, 49% use Internet news sites, 38% use social media, and 50% use other Internet websites daily.

Media stories collected from national and local news sources on hydraulic fracturing generally cover negatively related issues, and scientific evidence is mostly lacking. Coverage results become especially important given that knowledge of such issues are directly associated to the level of coverage. Meaning, the frequency a topic is covered in the media does seem to influence knowledge. And, perceived knowledge does seem to influence attitude toward hydraulic fracturing. The respondents were asked about the most prominent topics related to hydraulic fracturing found in the media. Results suggest that respondents are mostly aware of those topics as they relate to the process of hydraulic fracturing; however, they missed the questions that go more into detailed scientific technicalities. Moreover, although participants are informed about some aspects of hydraulic fracturing policies and regulations in Texas, they tend to overestimate the scope of those regulations. This suggests that people are more prone to think the State of Texas regulates more aspects of hydraulic fracturing than it actually does.

The knowledge questions also reflect on the attitudes that people hold about hydraulic fracturing and the level of their involvement in the subject. Since respondents displayed a general lack of knowledge about the specific science and regulations of hydraulic fracturing, respondents seem to have ambiguous attitudes about the topic. Here, 48% of respondents reported being neutral about whether the fracturing process is safe or unsafe, good or bad, or positive or negative. This

group could be considered a potentially good target of media campaigns directed at informing the public about hydraulic fracturing, as the information they receive should have a relatively larger influence on their overall attitude. This should be an important consideration for policy makers interested in promoting hydraulic fracturing agendas.

Developing stronger attitudes should also increase public involvement in hydraulic fracturing efforts (pro or against). Currently, people are generally neutral when asked about being involved in any such efforts and about the importance for the community. Respondents also do not see where politicians stand on the topic of hydraulic fracturing as a determinant of who they are going to vote for in the next elections (i.e., 66% are neutral). Given the significance of this issue in the upcoming policy making process, it is obvious that the public is generally unaware of the impact of hydraulic fracturing on their communities.

7 Sources/References

Audit Bureau of Circulation (2011). US newspaper search results. Retrieved from http://abcas3.accessabc.com/ecirc/newstitlesearchus.asp on 2011-07-18.

DMA

SRDS

Linkages to other White Papers

The above findings were forwarded to Prof. Suzanne Pierce in order to analyze them and compare them to the scientific research published on the topic.

Authors/contributors

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Appendix A. Keywords List Used for the Search

Well Blowout
Shale gas plus well blowout
Haynesville plus well blowout, Marcellus plus blowout etc
Chesapeake, Talisman plus well blowout
Shale gas well blowout plus cause, or mechanism
Shale gas well blowout plus citation or regulatory enforcement
Shale gas well blowout plus death and or injury
Shale gas well blowout plus groundwater contamination and or frac water release
Shale gas well blowout plus engineering report
Water Well Contamination
Ground water or Water well or aquifer contamination and fracing or fracking
Ground water or Water well or aquifer contamination and shale gasWater well contamination shale gas plus Marcellus, Haynesville, Barnett etc
Ground water contamination Shale gas plus Marcellus or Barnett or Haynesville etc
Ground water or water well contamination Shale gas plus methane
Ground water or water well contamination and surface casing, and/or well completion, and/or cement job
Water well contamination plus BTEX, and /or Benzene, diesel,
methanol (according to Waxman, Markey, DeGette report, most commonly used chemical in fracturing)
Water well contamination plus barium, and/or boron, bromine
Water well contamination plus arsenic, and/or chromium,
Water well contamination plus butanone (contamination from drilling, not fracturing, as you likely already know; not sure that drilling-contamination causation shown?)
Water well contamination plus uranium, NORM, radium, radioactive contamination, radon
Water well contamination plus acrylonitrile
Well and/or water supply and contamination and Southwestern Energy and Berish and Susquehanna (Berish = plaintiff in contamination lawsuit)
Lenox and township and contamination
Pavillion, Wyoming together with EPA, water well contamination, benzene,
"Price # 1 Well" (subject of lawsuit in Susquehanna County alleging well contamination)
Dish, Texas and/or …. water well contamination, emissions, air contamination, benzene
Range Resources, and Parker County, Texas, and/or water well contamination and/or EPA and/or RRC and/or hearings, and/or citation
Frac Fluid (and Frack Fluid)
Frac fluid and/or safety, benzene, diesel, carcinogenic, disclosure, composition
Frac fluid and/or ethylene glycol monobutyl ether
Frac fluid and disclosure
Frac fluid and groundwater contamination

Surface Spills or Accidental Release
Shale gas and Ground water or water well contamination and Surface spill and or accidental releaseSurface spill and/or shale gas and/or surface spill and or accidental release and/or drill pad or pad
Surface spill and/or shale gas and/or surface spill and or accidental release and/or Dimock / Stevens Creek / Cabot / Halliburton / Fiorentino (spill)
Surface spill and/or shale gas and/or surface spill and or accidental release and/or Susquehanna County / Springville / Cabot
Surface spill and/or shale gas and/or surface spill and or accidental release and/or Flower Mound, Cummings pad (spill)
Surface spill and/or shale gas and/or surface spill and or accidental release and/or Muncy Creek Watershed/ XTO Energy / Sugar Run (spill)
Surface spill and/or shale gas and/or surface spill and or accidental release and/or Williams / Louisiana / Caddo Parish / Schlumberger / Chesapeake /cattle kill (spill) Bradford Township / Schreiner Oil and Gas
Surface spill and/or shale gas and/or surface spill and or accidental release and/or Greene, Fayette, Washington County / Atlas Resources (waste discharges on surface)
McNett Township / Lycoming County (methane)
Hickory, PA
Garfield County, Colorado
Shale gas and/or surface spill and/or surface release and/or fish kill
Flow-Back Water
Flow-back water and shale gas and/or disposal and/or environmental issue, and /or recycling, and/or treatment and/or contaminants
Flow-back water and shale gas and/or Marcellus, Barnett, Haynesville etc
Tracy Bank (Buffalo) uranium and flowback or flow-back
Surface Water Disposal and land applicationShale gas and/or water disposal and/or fish kill
total dissolved solids
402 or NPDES or national pollutant discharge elimination system and permit and wastewater and flowback
POTW / publicly owned treatment works / wastewater treatment plants / flowback water disposal
Shale gas or Marcellus and trihalomethanes
land application and/or land farming
agriculture and/or field and/or spreading and fracture and/or flowback and wastes
Water Disposal Wells
UIC and/or well and/or permit and/or underground injection control and/or Safe Drinking Water Act
Heritage Consolidated LLC contamination chloride Cenozoic Pecos Alluvium Aquifer
Salt water injection well or Disposal well together with environmental contamination or problem, well integrity problem, cases pressure, groundwater contamination
Salt water injection well or Disposal well or class 2 well and shale gas and or Barnett and/or Haynesville and or Fayetteville etc
Hydro FX Injection Disposal Well west of Boyd, Wise County
Chico, Wise County 2005 injection well accident
Doc's Tank Trucks , Injection Disposal Well, Parker County, water pollution, casing pressure, down hole integrity problem
City of Annetta North, Parker County, Aledo, Increased salinity, deep Trinity water wells
Moratorium on new salt water injection wells Fort Worth
Class 2 disposal well PA; brine disposal well PA

Atmospheric Emissions and Air Quality
Shale gas and Atmospheric Emissions together with methane, and/or VOC, benzene
Shale gas and methane Emissions
Shale gas and methane Emissions and flow back water and/or well completion and/or gas processing
Shale gas and pipeline Emissions
TCEQ air quality study
Town of Dish Ambient Air Monitoring Analysis
Pipeline Leaks
Pipeline Leaks together with Barnett Shale or Haynesville etc
Pipeline leak, Enbridge Springtown Gas Plant
Pipeline line together with: shale gas or Marcellus, or Barnett etc and/or methane emissions, leaks, spills, accidents and/or Ingraffea
Regulatory Enforcement
Regulatory Enforcement together with: shale gas, and/or permitting, surface spill, water contamination, water disposal, blowout, ground water contamination, surface water release,
Frequency of inspection together with: shale gas, and/or permitting, surface spill, water contamination, water disposal, blowout, ground water contamination, surface water release,
PA DEP plus shale gas and/or enforcement, citations, spill incident, groundwater contamination, blowout, surface spill, surface release, stream release, publicly owned treatment works, wastewater treatment plants, flow back water disposal
TX RRC plus shale gas and/or enforcement, citations, spill incident, groundwater contamination, blowout, surface spill, surface release, flow back water disposal, well integrity, salt water disposal
New York Department of Environmental Conservation (DEC) and/or Supplemental Generic Environmental Impact Statement
Louisiana DEQ
Oklahoma DEQ
Arkansas DEQ
Susquehanna River Basin Commission
Delaware River Basin Commission and/or proposed regulations http://www.state.nj.us/drbc/naturalgas-draftregs.pdf
State Review of Oil & Natural Gas Environmental Regulations (STRONGER) [Does not issue fines or penalties but reviews adequacy of state programs and may review penalties issued.]
Local Government Response
Groundwater Availability Certification Parker County
Fort Worth gas drilling ordinance/ gas drilling task force
Arlington gas drilling ordinance http://www.marcellus-shale.us/pdf/Gas-Drill-Ord_Arlington-TX.pdf
Public Interest and Protest Groups
Riverkeeper (collects alleged cases of environmental contamination from drilling and fracturing)
Earthworks OGAP Oil and Gas Accountability Project
Natural Resources Defense Council
ProPublica
Ground Water Protection Council (nonprofit group of state regulators that has argued that state regulations of fracturing are adequate)
(pro) Marcellus Coalition
Barnett Shale Groups
Fort Worth Citizens Against Natural Gas Drilling Ordinance (FW CAN DO)
Erath Citizens for Clean Water
PARCHED Parker Area Residents Committed to Halting Excessive Drilling

Wyoming Groups
Wyoming Outdoor Council (trade secrets and chemical disclosure)
Marcellus Groups
Pennsylvania Environmental Council
Citizens for Pennsylvania's Future

Appendix B. Spreadsheet Items

Items included in the spreadsheets in which we have compiled our results:

- Date: date of the published article/ transcript
- Source: the name of the media source used to retrieve the article
- Title: the Headline or title of the article
- Author: person/group of people writing the articles
- Scale: whether the source is international national, regional/metropolitan to a city, or local to a certain city or town
- Keywords: the combination keywords from the list provided by the group used to conduct the search. Please note that in every spreadsheet, all the keywords are listed, whether or not they turned out search results. This will help us to observe which keywords are turning out results and which are not in each source.
- Reference to research: Whether or not the article includes any reference to a published study/report.
- Tonality: whether the article gives a positive, negative, or neutral connotations of hydraulic fracking. Please note that whenever an article presents different points of views, we categorized it as neutral.
- Link: the hyperlink where the articles are found online
- Text: The actual text of the article.

Appendix C: Online Attitude, Knowledge, and Behavior Survey Items

Your thoughts about Hydraulic Fracturing:

As of right now, how aware would you say you are about the issue of hydraulic fracturing?

1. Very aware
2. Somewhat aware
3. Not very aware
4. Not aware at all

Hydraulic fracturing is:

Safe	○	○	○	○	○	○	○	Unsafe
Good for the economy	○	○	○	○	○	○	○	Bad for the economy
Good for the environment	○	○	○	○	○	○	○	Bad for the environment
Important for energy security in the US	○	○	○	○	○	○	○	Unimportant for the energy security in the US
Positive	○	○	○	○	○	○	○	Negative
Useful	○	○	○	○	○	○	○	Useless
Important	○	○	○	○	○	○	○	Not important
Effective	○	○	○	○	○	○	○	Ineffective
Worthless	○	○	○	○	○	○	○	Valuable
Bad	○	○	○	○	○	○	○	Good
Harmful	○	○	○	○	○	○	○	Beneficial
Foolish	○	○	○	○	○	○	○	Wise
Unproductive	○	○	○	○	○	○	○	Productive
Helpful	○	○	○	○	○	○	○	Unhelpful

Knowledge about Hydraulic Fracturing:

The area where I live is rich in Shale gas.

a. True
b. False

Hydraulic fracturing is the process of producing a "fracture" in:

- The underground soil layer
- The topsoil
- An old mine
- The underground rock layer

In general:

A. There is a consensus that hydraulic fracturing is safe for the environment.
B. There is a consensus that hydraulic fracturing is dangerous and harmful to the environment.
C. Some scientists and environmental groups claim hydraulic fracturing is dangerous and should be banned, but the industry insists it is a safe technology.
D. The industry insists that hydraulic fracturing is dangerous and should be banned, but scientists and environmental groups think it is a safe technology.

More than three quarters of the hydraulic fracturing wells used in the United States produce:

A. Oil
B. Gas
C. Coal
D. Water

Nearly all of the natural gas wells in the United States use hydraulic fracturing.

A. True
B. False

Hydraulic fracturing requires _____ to retrieve natural gas trapped under the earth's surface.

A. Hammering solid rock underground
B. Injecting fluid underground
C. Extracting soil underground
D. Freezing underground water supplies

Hydraulic fracturing involves drilling under the Earth's surface for:

A. Less than 500 feet
B. 1,000-3,000 feet
C. 3,000-10,000 feet
D. 10,000-50,000 feet
E. More than 50,000 feet

Proppants are:

A. Gaseous material used to induce hydraulic fracturing
B. Compounds used to clean a fracturing site
C. Particles used to hold fractures open after a hydraulic fracturing treatment so that fluids can easily flow along
D. The legal permits required for drilling in fracturing sites

Texas now requires companies to disclose the chemicals they use in hydraulic fracturing.

A. True
B. False

The fracturing fluid is used to induce a hydraulic fracture by:

A. Over flooding the ground level surface area
B. Displacing ground water
C. Applying pressure to produce a crack in the natural rock formation
D. Washing out the soil to release pressure

During the fracturing process, if fracturing fluid seeps from the fracture channel into the surrounding permeable rock, this is called:

A. Fracture Gradient
B. Leak off
C. Frack Seepage
D. Natural Gas

Which of the following risks are associated with hydraulic fracturing? Choose all that apply.

A. Human health
B. The contamination of ground water
C. Risks to air quality
D. Migration of gases and hydraulic fracturing chemicals to the surface

The Ground Water Protection Council, Natural Resources Defense Council, FW CAN DO, and PARCHED are:

A. Gas drilling companies
B. Government agencies
C. Environmental Groups
D. TV shows

There is considerable scientific evidence that hydraulic fracturing has resulted in the contamination of water.

A. True
B. False

Well blowouts occur:

A. Frequently in drilling wells
B. When the drilling well explodes
C. When drilling fluids escape from the top of the wellbore under high pressure
D. When the weather conditions are bad

In general, blowouts that occur during the drilling process have an environmental impact similar to surface spills.

A. True
B. False

In the Barnett shale, there has been:

A. No blowouts
B. 20 or less blowouts
C. 20-40 blowouts
D. 40 or more blowouts

The Barnett shale area extends over:

A. 50 square miles
B. 500 square miles
C. 1,000 square miles
D. 5,000 square miles
E. 15,000 square miles

Drilling activity in the Barnett shale is regulated by the Railroad Commission of Texas (RRC) and:

A. Texas Department of State Health Services (DSHS)
B. Texas Commission on Environmental Quality (TCEQ)
C. Texas Department of Transportation
D. Texas Department of Agriculture

The Railroad Commission regulates how close a gas well can be drilled to a residential property.

A. True
B. False

The Railroad Commission rules do not include specific requirements for liners in drilling pits.

A. True
B. False

In Texas, there are standards for determining the locations, shapes and sizes of the drilling rigs.

A. True
B. False

Texas law allows drillers to use as much of the surface as necessary to explore, drill and produce the minerals from a property.

A. True
B. False

Texas Railroad Commission has no authority over the impact on property value as a result of drilling activities on properties.

A. True
B. False

In Texas, an oil or gas operator is required to perform an environmental study before drilling.

A. True
B. False

In the Barnet shale area, the annual water consumption for shale gas usage is:

A. Less than 2%
B. 2-4%
C. 4-6%
D. >6%

In Texas' Barnett shale, the number of active/producing horizontal wells increased from fewer than 400 in 2004 to more than _____ during 2010.

A. 1,000
B. 10,000
C. 20,000
D. 30,000

In 2010, the percentage of electricity in Texas produced from natural gas was:

A. less than 18%
B. 28%
C. 38%
D. 48%

In 2010, US shale gas production was _____ of total US natural gas production.

A. less than 3%
B. 13%
C. 23%
D. 33%

Media Use:

How often do youuse the following media?

	Never	Few times a year	2-3 Times a Month	Once a Week	2-3 Times a Week	Daily
Local Newspapers	○	○	○	○	○	○
Regional Newspapers	○	○	○	○	○	○
National Newspapers	○	○	○	○	○	○
Local Television	○	○	○	○	○	○
National Network Television	○	○	○	○	○	○
Cable Television	○	○	○	○	○	○
Local Magazines	○	○	○	○	○	○
National Magazines	○	○	○	○	○	○
Local Radio	○	○	○	○	○	○
National Radio	○	○	○	○	○	○
Internet news sites	○	○	○	○	○	○
Internet social media	○	○	○	○	○	○
Other internet websites	○	○	○	○	○	○

What websites do you use to get your news?

After answering the above questions in this survey, how aware would you say you are about the issue of hydraulic fracturing?

A. Very aware
B. Somewhat aware
C. Not very aware
D. Not aware at all

Perceptions about Hydraulic Fracturing:

Still thinking about the natural gas drilling process sometimes referred to as fracking, how concerned are you about this issue as it relates to water quality?

A. Very concerned

B. Somewhat concerned
C. Not very concerned
D. Not at all concerned

Do you think that state and national officials are doing enough to require disclosure of the chemicals used in natural gas drilling? Would you say they are...

A. Doing everything they should
B. Doing some of what they should
C. Not doing as much as they should
D. Not doing anything at all
E. Don't know

If you could speak directly to your member of Congress, your governor or state leader, which of the following statements would you be most likely to make to them?

A. When it comes to energy production, I come down on the side of the public's health and the environment. I favor cleaner energy sources that use the least water.
B. Energy production comes first. There are always risks and tradeoffs when it comes to public health and the environment.
C. Don't know

Which of the following statements best expresses your view about where America should focus its energy production in the future?

A. Water shortages and clean drinking water are real concerns.
B. America should put the emphasis on first developing new energy sources that require the least water and have minimal water pollution
C. Energy supply needs should override concerns about water shortages and water pollution.
D. America should proceed first with developing energy sources even if they may pollute water or create shortages.
E. Don't know

Behaviors:

Have you participated in any community efforts against hydraulic fracking?

A. Yes

B. No

Have you participated in any community efforts supporting hydraulic fracturing?

A. Yes
B. No

Community efforts (organizing, protesting, calling legislators, petitioning, etc.) related to hydraulic fracturing are:

worthless	○	○	○	○	○	○	○	valuable
good	○	○	○	○	○	○	○	bad
beneficial	○	○	○	○	○	○	○	not beneficial
unhelpful	○	○	○	○	○	○	○	helpful
productive	○	○	○	○	○	○	○	unproductive
wise	○	○	○	○	○	○	○	foolish
useful	○	○	○	○	○	○	○	not useful

Demographics:

In which Texas county do you live?

Denton	Clay	Eastland	Hood	Shakleford
Johnson	Comanche	Ellis	Jack	Somervell
Tarrant	Cooke	Erath	Montague	Stephens
Wise	Coryell	Hamilton	Palo Pinto	Young
Archer	Dallas	Hill	Parker	Other
Bosque				

What year were you born?

Gender

A. Male
B. Female

Political Affiliation (choose the most applicable.)

A. Republican
B. Democrat
C. Independent

Is your land currently being leased to gas industry operators?

A. Yes
B. No

Do you have a part-time or full-time employment related to hydraulic fracturing?

A. Yes
B. No

What is the highest level of education you have completed?

A. Less than High School
B. High School / GED
C. Some College
D. 2-year College Degree
E. 4-year College Degree
F. Master's Degree
G. Doctoral Degree
H. Professional Degree (JD, MD)

Are you (check as many as apply)

A. White
B. Asian (including Chinese, Korean, Japanese and Southeast Asians
C. Pacific Islander
D. Native American or Alaskan native
E. Hispanic or Latino origin
F. African American

G. Other

What is your household income?

Below $10,000	$60,000 - $69,000
$10,000 - $19,999	$70,000 - $79,999
$20,000 - $29,999	$80,000 - $89,999
$30,000 - $39,999	$90,000 - $99,999
$40,000 - $49,999	More than $100,000
$50,000 - $59,999	

Appendix D. Links to Spreadsheets

- Online search
    - https://spreadsheets.google.com/spreadsheet/ccc?key=0AjCqmaiHbS-ydFg5Sy1jaHFYOXJRSUMyUjVUdzZ0a1E&hl=en_US
- National TV and Radio:
    - https://spreadsheets.google.com/spreadsheet/ccc?key=0AjCqmaiHbS-ydFlib1lEczk3cXVjbGZYYUt5UThDLVE&hl=en_US
- National Newspapers:
    - https://spreadsheets.google.com/spreadsheet/ccc?key=0AjCqmaiHbS-ydE9RX3IteS12VlAwRDBRT0FBbkd3N0E&hl=en_US
- Marcellus Metropolitan TVs
    - https://spreadsheets.google.com/spreadsheet/ccc?key=0AjCqmaiHbS-ydGJJby01cjZ3bUNUVXhkZUNFaVJJSEE&hl=en_US
- Marcellus Metropolitan Daily Newspapers
    - https://spreadsheets.google.com/spreadsheet/ccc?key=0AjCqmaiHbS-ydFFoTUN5NXdXeGsxaGR1Qkg4WUFtMGc&hl=en_US
- Barnett Metropolitan TVs
    - https://spreadsheets.google.com/spreadsheet/ccc?key=0AjCqmaiHbS-ydGVmY1lZSjNRRS1lSmtGTHFyMWJKc1E&hl=en_US
- Barnett Metropolitan Daily Newspapers
    - https://spreadsheets.google.com/spreadsheet/ccc?key=0AjCqmaiHbS-ydFB0OFhBQVhMYzJGU25LUDUzMnUweUE&hl=en_US
- Haynesville Metropolitan TVs
    - https://spreadsheets.google.com/spreadsheet/ccc?key=0AjCqmaiHbS-ydDBvLXRYckFTRklJdUFxUHJoVU5qLWc&hl=en_US
- Haynesville Metropolitan Newspapes
    - https://docs.google.com/spreadsheet/ccc?key=0AjCqmaiHbS-ydEhYaTdya0RHTnFpVEdhQ0lBTllTQlE&hl=en_US#gid=0

4 Environmental Impacts of Shale Gas Development

This section is still in draft form.

energy institute
The University of Texas at Austin

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1 Introduction

Hydraulic fracturing has been used by the oil and gas industry since the late 1940's (Sallee and Rugg, 1953). Over the next 50 years the oil and gas industry used fracturing technology to stimulate on the order of a million wells. The Independent Petroleum Association of America, an industry Trade Association has suggested (with strong justification it would seem) that hydraulic fracing is a technology that is critical accessing the US's oil and gas resources in a cost effective manner (IPAA, 20XX). The exploitation of shale gas resources in North America has had such a dramatic and profound impact on both gas production and in the long term reserves of natural gas that it has been deservedly acclaimed as a "game changer" for North America by energy analysts (ICF, 2010).

Shale gas occurs in fine grained organic rich rocks that were originally recognized as source rocks for hydrocarbons but were long thought to be to impervious to be exploited for their gas content. Developing an approach to cost effectively producing natural gas from these rocks was accomplished over a period of years by a determined small gas company operating in the Barnett Shale of Texas. This approach refined the hydraulic fracturing technique and eventually combined it with horizontal drilling. The success of these stimulation and associated well-completion techniques led to a revolution in the natural gas industry.

The report by ICF International on gas shale identified three critical environmental concerns: (1) water requirements; (2) chemical exposures; and (3) management of contaminated water. Shale gas has become a contentious and polarizing issue, with both sides expressing almost exacting opposite views of the facts. Some segments of the public have become deeply suspicious of the veracity and motives of gas companies. These suspicions were intensified over that last few years by the natural gas producers and gas field service companies initially refusing to disclose the chemical makeup of fluids used to enhance hydraulic fracturing. Anecdotal evidence suggests that in areas of intense shale gas drilling many of the local public have a low degree of trust of gas producers, gas field service companies and in many cases the regulatory agencies. All of this has undoubtedly intensified a widespread outcry on internet blogs, in social media, and documentaries asserting that shale gas drilling and production is an environmental disaster on an unprecedented scale. A presentation at a recent annual meeting of the Society of Petroleum

Engineers (SPE) warned that future shale gas operations "depend in part on public support" and that such support in the future may be "jeopardized by unresolved [largely environmental] issues" (Fanchi and Fanchi, 2011).

Many outside observers have concluded that it is "likely", "highly likely" or "definitively proven" that shale gas extraction is resulting in widespread contamination of groundwater in the US. For example Wood et al (2011) in a comprehensive study of the impacts of shale gas exploitation in the US, from the Tyndall Center at the University of Newcastle, have concluded that "there is considerable anecdotal evidence from the US that contamination of both ground and surface water has occurred in a range of cases". Other scientists have seen even greater clarity in the evidence. For example Robert Howarth,the David R. Atkinson Professor of Ecology & Environmental Biology at Cornell University, in a formal written submission to the EPA, has stated "Shale gas development clearly has the potential to contaminate surficial groundwater with methane, as shown by the large number of incidences of explosions and contaminated wells in Pennsylvania, Wyoming, and Ohio in recent years" (Howarth, 2010). In the next paragraph of his submission Howarth expresses even greater certitude, stating "… shale gas development has clearly contaminated groundwater and drinking water wells with methane…". Such statements from prominent scientists have increased public anxiety regarding hydraulic fracturing in general and shale gas drilling in particular.

In general the response from the gas industry and its supporters has been total denial not only that any such problems exist but also that such issues are real risks. For example the industry sponsored web site Energy-in-Depth (EID), in response to a white paper by the NGO Food & Water Watch, flatly denied the validity of "[an allegation that] fracking fluid migration underground" are among the "environmental and public health risks" of hydraulic fracturing and shale development. In response to a question from Congressman Matheson on the safety of hydraulic fracturing in a congressional hearing in 2010, Rex Tillerson the Chairman of Exxon Mobil stated that "there have been over a million wells hydraulically fractured in the history of the industry, and there is not one reported case of a freshwater aquifer ever having been contaminated from hydraulic fracturing, not one" (CEC, 2010). At times the statements of the supporters of the gas industry have been even more strident. Michael Economides, Professor of Chemical and Biomolecular Engineering of the University of Houston, recently told a

Congressional Committee that "the hydraulic fracturing process is safe, already well regulated by the various States" and that "the hysterical outcry over this process is completely unjustified" (Economides, 2011). He also asserted in his testimony that "documentaries such as Gasland, and the national media have fueled a frenzy of anti-fracturing sentiment previously unknown". Economides has also referred to arguments made by the environmentalists as "two huge lies" and another of their concerns as "preposterous". Although from a scientific viewpoint this epithet may be justifiable, this kind of language degrades the tenor of the debate. There are U-tube videos circulating where at least one academic opponent of hydraulic fracturing in a state of high agitation, express his concerns in a manner not conducive for rational discussion. Some opponents of hydraulic fracturing have escalated the argument by attempting to have hydraulic fracturing declared a violation of human rights by the United Nations (UN, 2011).

Mark Boling (Executive Vice-president of Southwestern Energy, a major shale gas company) in a recent presentation has appealed to both sides in the shale gas debate to "Dial down the rhetoric" and to work to understand the "real obstacles to responsible development of [shale gas resources]." He suggested that only if the focus was placed on these "real obstacles" that solutions will be developed. Dr Cal Cooper of Apache Corporation has expressed some similar themes in his Congressional testimony. He noted that Apache "would be pleased if the U.S. scientific community were to conduct robust scientific investigations that better establish the risks of hydraulic fracturing on drinking water resources". He also noted that 'based on existing knowledge and practical experience" that his company believes that the risks "are minimal and manageable". Finally he cautioned that "alarmist sensationalism, especially when it purports to be science, is destructive, and this topic has enjoyed more that it's fair share of that already".

The question of whether hydraulic fracturing has directly contaminated fresh water aquifers is controversial in some part because of differing sematic distinctions drawn by the protagonists. The gas industry and the supporters of hydraulic fracturing tend to see hydraulic fracturing as a particular technology that is applied to the deeper extremity of gas (or oil) wells, typically at depths of a thousand meters or more below fresh water aquifer. The gas industries assertion that no "definitive evidence" has been found of "direct" water contamination from "deep" hydraulic fracturing is undoubtedly true if the sentence is parsed pedantically. However the use of nuanced denials is unlikely to increase public confidence in the shale gas industry. At the same time for

the opponents of the technology, hydraulic fracturing is seen as a broad term that covers the drilling and completion of the well and all the associated activities. Under this view a truck of hydraulic fracturing fluid rolling over going around a tight bend and spilling its load onto the ground is contamination from hydraulic fracturing. Professor Mark Zoback of Stanford University was recently quoted by Dittrick (2011) as stating "There are significant environmental impacts to shale development, but none of them have anything to do with hydraulic fracturing".

Hoffman (2011), representing the Susquehanna River Basin Commission has appealed for science-based decision making for regulations of shale gas extraction from the Marcellus (Hoffman, 2011). Unfortunately scientific research has not kept pace with the "shale gas revolution". Ben Grumbles (former Assistant Administrator of the EPA for water in the G.W. Bush administration) writing in Yale-Environment-360 (Y-E-360, 2011) suggested that "local and national policymakers need an honest assessment of potential safety risks [associated with shale gas]". Soeder (2010) has suggested that the rapidity of the expansion of shale gas drilling may result in "regulatory agencies [making] policy decisions based on little data". Taking a different perspective, some energy experts have expressed concerns that "If the regulation of hydraulic fracturing becomes more stringent, this could slow the growth of shale gas production" (ICF, 2010). Shale gas production is particularly susceptible to regulatory slowdown as production rate is sensitive to the rate of drilling (because shale gas wells produce most of their gas in a year or so). As reported by National Public Radio Governor Corbett of Pennsylvania, under considerable pressure from environmentalists to increase regulatory oversight of shale gas extraction, has said that "We need to protect the water… We need to protect the environment. But we must do it based on science and not emotion."

This paper (by necessity for conducting a comprehensive evaluation) takes a broad view of the environmental impact of hydraulic fracturing, placing it in the context of the full range of environmental concerns related to not only fracturing, but also drilling, water supply, waste disposal and so on. Soeder (2011) amongst others, has suggested that two main aspects of attempts to minimize the potential environmental impacts of shale gas extraction require more attention: (1) understanding the "long-term and cumulative" effects on "landscape, terrestrial and aquatic ecosystems, water resources, and air quality"; and (2) Understanding whether current regulations, and regulatory enforcement (numbers of regulatory staff) are sufficient. Soeder

(2011) has also expressed concern as to whether it is understood which potential environmental impacts are most important.

The range of environmental concerns engendered by shale gas production includes:

- Water resources issues, including the magnitude of withdrawals, problems with the disposal of produced water
- The potential toxicity of chemicals in hydraulic fracturing fluids and their long term fate in the subsurface
- Surface spills (of fracturing chemicals, produced water, or condensate)from trucks, tanks and pipelines
- Contamination of groundwater by surface spills or leakage from wells with poorly completed surface casing and cement
- Disposal of drilling wastes and NORM (naturally occurring radioactive material) from produced water and scale deposits
- Blowouts of wells , well head accidents resulting in surface spills of hydraulic fracturing fluids, produced water or condensates
- Road traffic, noise and light pollution caused by drilling activity, pipeline compressors and so on.
- Ecologic damage caused by habitat fragmentation and pollution of streams by chemicals and/or sediment
- Emissions of VOC and methane (and possibly H2S) impacting air quality
- Seismic activity possibly induced by fracturing or salt water disposal wells

Shale gas production also has a direct human impact, more so than traditional oil and gas production. A recent White Paper summarizing a Society of Petroleum Engineering Technical Summit (SPE, 2011) on the topic "Hydraulic Fracturing: Ensuring Ground Water Protection" noted that shale gas has resulted in intensive "industrial activities" in rural and sub-urban previously not familiar with such activity. And that this has resulted in a range of social impacts ranging from noise from drilling rigs and heavy equipment, and high levels of truck traffic. The report (SPE, 2011) notes that the influx of out-of-town, industry workers "changes the sociological dynamics of small communities".

This paper sets out to critically review available scientific information addressing these issues. In writing this paper not only has the scientific literature been reviewed but also an extensive sampling of reports by NGO's, regulatory agency reports, homeowner complaints and newspaper

articles. In all this sources a particular emphasis was put on tracking down chemical analyses of water well chemistry, original reports on emissions measurements, health reports, and similar tangible evidence. It should be noted however that a single chemical analysis done by a home owner at a single commercial laboratory lacks the veracity of an EPA chemical analysis done at multiple specialized laboratories using triplicate samples. In some cases scientific studies are lacking or inconclusive and assessment of analogues is all that is available. A question of particular importance whether the deep fracturing fluid can have an appreciable impact on fresh water aquifers in the long term. The overall aim of this paper is to attempt to evaluate the nature of the potential environmental risks and understand their potential for substantial impacts. It also attempts to identify best practices that should be considered for future legislation and/or rule making by regulatory agencies.

2 Environmental Impact of Usage and Disposal of Water

2.1 Quantity of Water Usage

The drilling and hydraulic fracturing of a shale gas wells requires significant quantities of water: for use as drilling mud, for the hydraulic fracturing fluid, for extraction and processing of proppant sands, for testing of natural gas transportation pipeline, and for gas processing plants to name a few. Water usage is one of the most frequently mentioned environmental issues associated with shale gas production and hydraulic fracturing technology uses significant quantities of water. Some refer to the water usage associated with hydraulic fracturing as "large" and some as "vast". The EPA (EPA, 2011) has estimated that if 35,000 wells are hydraulically fractured each year in the United States, then this would consume an amount of water equivalent to that used by five million people. However it is important to put this water usage into the context of how much energy is produced through the drilling activity and also to understand if the consumption is sustainable.

The water required to hydraulic fracture a single well has varied considerably over the last decade as hydraulic fracturing for shale gas has become dominated by more complex, multi-stage horizontal wells. Table (1) shows the estimated average current (October 2011) water consumption for hydraulic fracturing for a number of shale gas plays or basins from Chesapeake Gas data presented in Mathis (2011). This data shows that shale gas plays vary about 4 to 6 million gallons their per well water requirements.

Table One: Current Chesapeake Water Use by Shale Play

Shale	Gallons Used for Drilling	Gallons Used for Fracturing	Million Gallons Used per Well
Barnett	250,000	3,800,000	~4.0
Haynesville	600,000	5,000,000	~5.6
Fayetteville	65,000	4,9000,000	~4.9
Marcellus	85,000	5,500,000	~5.6
Eagle Ford	125,000	6,000,000	~6.1

Several metrics have been used in an attempt to quantify the significance of water usage in shale gas production. The most popular has been the energy water intensity (typically expressed as m3 of water per TJ of energy), used by Gleick (1994) in his seminal paper on the water energy

nexus. Mantell (2011) has estimated the water intensity of the Barnett shale, Marcellus shale and Haynesville shale plays as 1.32, 0.95, and 0.84 gallons per MMBtu, respectively. Mantell notes that these water intensities are low compared to the water intensities calculated by Gleick (1994) for other types of energies by one or two orders of magnitude. Nicot and Scanlon (2012) have calculated the average water intensity for shale gas production in Texas for 2008 as 4.6 L/GJ. Note that Nicot and Scanlon's estimated water intensity if for the overall drilling in the play including both vertical and horizontal wells, as well as wells from both high producing and marginal areas. The calculation of the water intensity metric for shale gas wells is somewhat uncertain because of uncertainty in the projected life time gas production of shale gas wells. However there appears to be a consensus amongst researchers working in this field that for most all shale gas well the water intensity is small compared to other types of fuels such as coal.

Another possible metric is the water consumption per head of local population by area or by political subdivision (such as by county or by state). For example Ramudo and Murphy (2010) quoting Josh Brown from Chesapeake Energy, note that Pennsylvania's annual total water consumption is approximately 3.6 trillion gallons, of which the shale gas industry withdraws about 0.19% for hydraulic fracturing.

Significantly the water usage for hydraulic fracturing is a short-term and transitory (Arthur, 2009). The vast bulk of the water usage related to a specific well, takes place over a short period of time (on the order of days to a few weeks), while the hydraulic fracturing activity takes place. Infrastructure (particularly gas pipelines, water distribution pipelines) is important for cost effective exploitation of shale gas resources. As a results water usage tends to be highly concentrated in space and time, as particular companies and in some cases alliances of companies expand drilling activity to an area in concert with development of the necessary infrastructure. From the perspective of a small geographic area undergoing intense shale gas development the water intensity of shale gas in m3 per TJ is not a relevant metric to represent the local impact of water consumption. The variety of water sources and the fact that pipelines or trucks may be bringing in water from considerable distance means that it is almost impossible to develop a detailed understanding of the local impact of water usage.

The first systematic study of water sources for shale gas extraction was undertaken in 2006 for the Barnett shale play by Harden and Associates in collaboration with J.P. Nicot of the

University of Texas (Bene et al., 2007). The Bene et al. study was particularly concerned with understanding what impact the rapidly growing Barnett shale play was having on groundwater in the region and specifically the impact on the trinity aquifer, which supplied much of the water for small communities in the rural counties around Dallas and Fort Worth. Bene et al. (2007) estimated that in 2005 nearly 90% of the total water withdrawals for the region for their study area (municipal, agricultural irrigation, thermo-electric power generation, industrial, and mining) comes from surface water, whereas groundwater supplies the rest. The total water withdrawals for the Barnett Shale development was estimated as less than 1 percent. The demand on ground water from gas shale drilling was about 3% of all groundwater total groundwater withdrawals.

Nicot (2007) made predictions for the future water needs for Barnett Shale development in the context of low medium and high scenarios for the rate of exploitation of the gas resource. It has since become clear that the path of development has been between the medium and the high estimate (Nicot and Scanlon, 2012). The high estimate predicts an increase, from an estimated 7,200 acre-feet in 2005, to about 10,000-25,000 acre-foot per year by 2025. Nicot (2007) estimated an increase in groundwater used from 3% in 2005 to 7 to 13 percent in 2025. These estimates for groundwater consumption will likely prove high as increasingly water usage in the Barnett Shale Play has increasingly been sourced from surface water, an inherently renewable source. In a recent comprehensive study of water usage in shale gas production Nicot and Scanlon (2012) computed the cumulative water use in the Barnett totaled 145 Mm^3 from 2000 to mid-2011 and cumulative gas production over that time was They also have shown that not surprisingly, the cumulative gas production track cumulative water consumption over time. Annual water use by the entire shale gas industry in the Barnett represents approximately 9% of water use in in the City of Dallas (Nicot and Scanlon, 2012).

2.2 Sources for Water

Water for drilling hydraulic fracturing shale gas wells can be sourced from surface water (rivers, lakes, ponds), groundwater aquifers, municipal supplies, reused waste water from industry or water treatment plants, and recycling water from earlier fracturing operations (Arthur and Coughlin, 2011; Veil 2010). The main environmental concerns are that water withdrawals for shale gas drilling will result in reduced stream flow or deplete groundwater aquifers. Significantly the source of water used has varied considerably from area to area. Water impacts

are inherently a local matter and the exact location and the seasonal timing of the withdrawal can be a critical difference between high impact and no impact on other users.

The most reasonable approach to assessing the significance of the water usage is to consider what impact it has on the local community and the local environment both in the short and long term. In the early days of shale gas production water was brought to the site by trucks. This form of transporting water is expensive and the scale of truck traffic is disruptive for the local community. On the order of a 1,000 truck trips to the well site may be required for a modern hydraulic fracture job, a third or more of the trucks carrying water for fracturing. Trucking is expensive ($0.75 to $1.00 per barrel per 30 miles of route). Therefore there is a strong economic incentive to either source water locally or to develop a pipeline system for water delivery (and disposal). Pipelining water both lowers cost and decreases issues related to truck traffic.

The sources for water used for hydraulic fracturing in most states is not well documented (see for example the situation in Texas noted in Nicot and Scanlon, 2012), in large part because of the complex patchwork of regulatory agencies that are responsible for various water sources in the states mostly do not monitor consumption. Perhaps the key distinction between water sources in terms of their environmental impact is whether the water usage is sustainable, in other words, renewable. For example surface water usage is likely to be sustainable whereas groundwater usage is less likely to be sustainable. For each shale play the ratio of groundwater to surface water withdrawals can vary considerably bother in time and location.

Again in the Barnett, Bene et al., (2007) estimated that in 2000, the groundwater use for gas well drilling and fracturing was approximately 3 percent of the total groundwater use in their study area. By 2005 water usage had grown substantially and Bene et al. (2007) estimated that the water consumption for gas well was 7,200 acre-feet with approximately 60 percent being groundwater from the Trinity and Woodbine aquifers and 40 percent being from surface water sources.

Usage of groundwater and farmers ponds is more typical than river water in the early stages of the exploitation of a shale gas play when drill pads are typically geographically dispersed and before pipeline based water-distribution systems are established. For example Bene et al. (2007) estimated that, early in the development of the Barnett shale gas (in 2005–2007), between 45 and

100% (depending on the location) of the water for hydraulic fracturing came from groundwater aquifers. At the same time this usage was relatively small compared to other sources of consumption. Mace (2007) presented data that shows that water levels in groundwater wells in the three aquifers underlying the Barnett shale play (the Trinity, the Paluxy, and the Woodbine) have been in approximately linear decline over the last hundred years. In 2005 the water usage from the Trinity aquifer (the main aquifer overlying the area of the Barnett Shale under development at the time, was 8000 acre feet , 1.6% of the annual pumping from this aquifer (Groat 2006). Except locally (for domestic or farm water wells close to major extraction wells for shale gas water) it seems unlikely that the impact of an additional 1.6% of annual groundwater withdrawals could be discerned from the noise in water levels declines for this aquifer.

Nicot (2010) has made a first order inventory of the various water sources available to operators within the Barnett Shale footprint including: (1) water from wastewater treatment plants; (2) groundwater from "smallish possibly slightly brackish aquifers"; (3) farm ponds; and (4) other non-state surface water bodies. The approximate annual water availability from these sources is 100,000 AF from ponds and non-State surface-water bodies, over 100,000 AF from wastewater outfalls, and more than 25,000 AF from small often brackish aquifers. These water resources are a factor of five greater than the maximum annual consumption for the Barnett of 40,000 AF projected by Nicot. Although there may often be a mismatch between available water sources and the location of drilling, as the Barnett play has matured operators have increasingly developed pipeline networks to resolve such issues.

On a regional basis the groundwater withdrawals for gas wells are such a small volume compared to total withdrawals (by agriculture, municipal, manufacturing and so on) it would be difficult to distinguish their impact except at a local level. Such distinct negative impacts on specific local water wells have been observed in some domestic wells perhaps within the cone of depression of wells particularly active in supplying gas companies. For example in 2006 in Parker County, the local newspapers had a number of stories of property owners water wells running dry in response to water usage for hydraulic fracturing and the local Sierra club and other environmental activists were expressing strong concerns (Chruscielski, 2007). There is evidence that this pressure from the local population resulted in gas companies lowering their

water consumption. For example from January 2005 to March 2007 one company operating in the Barnett shale play (Devon) reduced their water consumption per frac job by a half (Degner, undated).

Galusky (2010) has noted that early projections for withdrawals of freshwater for hydraulic fracturing of gas wells in the Barnett had assumed that groundwater would come to represent 100% of usage as the play was fully developed. Although Rahm and Riha (2012) have suggested that "ground water is the major source of water for hydraulic fracturing [in the Barnett Shale in Texas]", this has not been true since 2006 when groundwater usage was estimated by Galusky (2007) as 56% of the usage for fracturing. By 2007 Galusky estimated that groundwater usage had fallen to 41% of usage. As noted by Galusky (2010) after 2007 s hale gas activity in the Barnett has been concentrated in the so-called "core areas" largely in the more urban areas and a "substantial fraction" water for gas wells "has come entirely from municipal purchases", essentially all from surface water sources. Galusky (2010) concluded that "it is likely… that the fraction of groundwater [resource used by the Barnett shale activity] will be considerably less than the 10% figure originally projected by [Bene et al., 2007]".

In part of the Barnett Shale play companies have made minor use of brackish water aquifers as source. API (2010) states that gas companies working in the Barnett shale "are drilling to the Lower Trinity aquifer to supply water [for their needs]". The Lower Trinity aquifer has such high TDS content it cannot be used for domestic use without expensive treatment. It is not clear what proportion of current groundwater usage is from these brackish sources. Anecdotal evidence talking to operators suggests that where convenient operators recycle the early less saline portion of the flowback water. Both reuse of flowback and usage of brackish water is accomplished through use of in-line filtration, and in some cases centrifuge/chemical treatment.

In contrast to the Barnett Shale, when the Haynesville Shale play began to be exploited in East Texas and western Louisiana, water initially dominantly came from the Carrizo-Wilcox aquifer (Hanson, 2010). Although the local recharge rate of this aquifer is not well understood local water experts and landowners were concerned that water for hydraulic fracturing was not been produced in a sustainable manner. Anecdotal evidence suggests that these concerns were driven by observations of unexpected drops in the water levels in community wells in areas where it was known that significant abstractions were being made to supply drilling needs. Van Biersil et

al. (2010), in evaluating the sustainability of the Carrizo-Wilcox as a water source for future Haynesville gas drilling, concluded that aquifer is "subject to elevated drawdown and large capture zone", has "locally poor productivity", and thus "is of limited use as a large water producer".

In October 2008, Jim Welsh the State of Louisiana's Commissioner of Conservation Jim Welsh issued a groundwater advisory recommending that companies developing the Haynesville Shale in Northwest Louisiana should use the more sustainable Red River Alluvial aquifer system (that because of its hardness and high TDS, is mainly suitable for industrial uses) in preference to the Carrizo-Wilcox (Welsh, 2011). The Commissioner further encouraged surface water or other alternative water sources where practical.

At the same time the commission pointed companies towards two very large surface water in Northwest Louisiana, the Toledo Bend Reservoir (to the west), and the Red River (near the center of the Haynesville Shale play), as sources of water for fracturing with about 300-billion gallons available annually (Welsh, 2011). This strategy has proved successful in getting the gas companies to lower their withdrawals from the Carrizo-Wilcox; by March 2010 73% of the water used in the Haynesville play was surface water, and the rest was groundwater (DNROC, 2011). At the same time the entire water usage by the hydraulic fracturing industry was, according to Mathis (2010), 1.6% of the entire water consumption of within the eight parishes (Louisiana) and four county's (Texas) within the area of the Haynesville Shale play. By far the largest operators in the Haynesville play over the last few years have been Chesapeake, Encana and Petrohawk. Mathis (2010) notes that Chesapeake uses 90% surface water for its Haynesville operations. In May 2009, Chesapeake was the first gas company to receive an Army Corps of Engineers' permit to withdraw water from the Red River. Hanson (2010) suggests that Petrohawk now uses no groundwater in its hydraulic fracturing operations. As companies have responded to community concerns, water demand for the year from October 1, 2009 to September 30, 2010 being met primarily (78 percent) by surface water. The Louisiana Office of Conservation is now confident that the Carrizo-Wilcox aquifer will not suffer long-term negative impacts related to water demands for gas drilling.

In response to these concerns the gas industry has progressively changed the water sources for their operations to renewable sources such as the Red River aquifer (Van Biersil et al., 2010) and

in some cases to the use of municipal waste water. EXCO Resources announced plans to use partially treated waste water from an International Paper a mill in an 8 mile 12 million gallons-a-day pipeline. This wastewater is low in oxygen which reduces the need to use biocides in frac fluid to control bacteria.

The current core of Eagle Ford Shale play encompasses than a dozen counties in South Texas, extending some 6,000,000 acres from Webb County in the southwest to Gonzales in the northeast. In the Eagle Ford shale play in south Texas, fewer options are available for water. The total water withdrawals from groundwater and surface water sources from the area encompassed by the current Eagle Ford shale play in 2008 was approximately 64.8 billion gallons (Chesapeake, 2011). The main fresh water use is for agriculture (70%) and municipal water supply (26%). Surface water options are few except near the Rio Grande along the border with Mexico. Nicot and Scanlon (2012) have noted that surface water is not readily available in this area and that apart from the Rio Grande the streams in the area such as the Frio and Nueces Rivers are ephemeral.

Thus far shale gas/oil drilling has largely tapped groundwater from the Carrizo aquifer. In Texas the southwestern portion of the Carrizo-Wilcox Aquifer has been significantly depleted by unsustainable extraction from water wells going back before 1900, with water levels declined on the order of 130 m over the last hundred years in some parts (Greene et al., 2007). As noted by Green et al. (2009), high rates of pumping in the 1960s, aggregating to more than 100,000 acre-ft per year continued through the mid-1980s, before decreasing by about 35% thereafter. Green et al. (2009) also suggested that the average total annual recharge of this southwestern Texas portion of the Carrizo-Wilcox Aquifer "may be less than 30,000 acre-ft" which is considerably below the current rate of aggregate pumpage.

Local short-term water shortages within the Eagle Ford shale play are perhaps inevitable and the gas shale industry appears to recognize that proactive strategies will be needed to avoid conflicts with local communities. Options that can mitigate local water shortages include: either pipeline or truck transport of Rio Grande surface water or Carrizo groundwater to areas with water issues; recycling using mobile desalination plants; reuse of flowback water blending with fresh water; and use of brackish or low quality groundwater from aquifers other than the Carrizo; and use of treated municipal waste water. Thus far no information is available to allow even estimation of

what impact these strategies have had on lowering the shale gas related withdrawals from the Carrizo. However reports in Texas business web sites suggest that water treatment companies have seen the Eagle Ford shale play as an opportunity for selling significant volumes of desalination services.

The Fayetteville Shale play in north-central Arkansas, active since 2001 (with over 3,000 wells drilled), is the 4th largest recoverable gas play in the country. Concerns over the impact of gas development on water resources have been driven in part by the fact that the play is close to a broad swath of eastern Arkansas that has chronic groundwater shortages. In the Fayetteville Shale play in Arkansas, gas companies use water from surface water (rivers, private lakes and ponds), reuse of flow-back water from previous fracking operations, and "limited use" of groundwater from private water wells (Chesapeake,2010). The main area of drilling in the Fayetteville shale play in White County is west of, and abuts the area of eastern Arkansas that has been designated as a critical area for groundwater shortage by the state (ANRC, 2012). To gather rain water the gas companies operating in the Fayetteville play have constructed a series of impoundments. Chesapeake in 2008 also constructed a large (500 acre feet) impoundment to divert water from the Little Red River during periods of high flow (Arthur, 2008). Water for this reservoir is withdrawn River by the operators during periods of high flow (storm events or releases for hydro power generation from an upstream Dam). The operator is permitted to withdraw up to 1550 acre-ft each year. Southwestern which controls nearly a half of the Fayetteville uses 100% surface water in its operations (36% from their own constructed impoundments, 26% from private ponds, 21% from reuse of flowback, and 17% direct withdrawals from streams (SWN, 2012). It would seem that essentially all the water for the Fayetteville shale play is derived from surface water sources and reuse. The USGS continuously monitors stream flow at seven sites within the area of the active Fayetteville Shale play so any significant overuse of surface water could be readily detected. This seems unlikely as most of the water used comes from rain feed ponds.

Pennsylvania receives an average of 43" precipitation per year and on the order of three times the water available compared to Texas, where gas shale drilling was pioneered. Pennsylvania consumes about 1.6% of the water available. In the Marcellus Shale Play in Pennsylvania, Hoffman (2011) has documented the actual water use for hydraulic fracturing within the SRB

using water regulated by the Commission. For Marcellus gas wells between 6/1/08 to 6/1/11 Hoffman reports that 724 shale gas wells were fractured using a total volume of 2,135.8 million gallons of freshwater, 32% from public water supplies (from surface water in more than 95% of the cases, Hoffman, 2011) and 65% from direct surface water withdrawals, mostly from rivers and streams. The average volume of water injected per well drilled and fractured was approximately 4.3 million gallons, 90% from freshwater and 10% from recycled flowback. For the 36% of water coming from public supplies, Entrekin et al. (2011) have computed that the average distance between Marcellus shale gas wells and the nearest public water supply in Pennsylvania is 25.83 ± 17.93 Km. The actual road trip for tanker trucks would be longer than this. However it is likely that wells at a larger distance from city supply preferentially get their water from surface sources. As the Marcellus Shale Play has matured an increasing portion of this water is being sourced from surface water that has been transported by pipeline networks. Recently reuse of flowback water has become a significant component of water for hydraulic fracturing with reports of 75% or higher rates (Rassenfoss, 2011). This reuse rate would correspond to approximately 15% of the water consumption for hydraulic fracturing. Rassenfoss (2011) suggests that in the future acid mine drainage water from coal mines may become a source of water for shale gas activities.

Rahm and Riha (2012) have recently reviewed some of the regulatory restrictions in place in Pennsylvania to prevent withdrawals from streams so large that they will result in ecological damages. They note that ‘‘Large’’ rivers (defined as rivers with a median flow >2830 l/s or 1000 ft3/s) will seldom have low flows requiring regulatory intervention to curb withdrawals. They show as stream size decrease the number of days with regulatory control of withdrawals become larger. Again as the Marcellus play matures pipeline infrastructures linking drill pads to withdrawal sites on large river via large storage impoundments will become widespread. In New York, the draft SGEIS has proposed a protective stream withdrawal regulation that states “Water Consumption: Companies will not only have to follow Susquehanna River Basin Commission and Delaware River Basin Commission protocols for water withdrawal where applicable, but also must complete a more stringent and protective stream flow analysis in regards to water withdrawal plans – whether inside or outside the Susquehanna or Delaware basins”.

The Horn River Basin is a shale gas play (ranking third largest in North America in reserves) in NE British Columbia Canada, approximately 1600 km NW of Calgary, Alberta. In the Horn River Basin of British Columbia surface water resources are limited because the area of shale gas activity does not have any significant through-flowing rivers, substantial lakes or other significant sources of surface water. For this reason hydraulic fracturing has been sourced largely from small lakes (such as Two Island Lake) and groundwater. In response to the potential impact of groundwater extraction the gas companies operating in this shale play have attempted to utilize brackish and saline water sources (Coppola and Chachula, 2011), lower the amount of water used for fracturing and implement recycling where possible. The British Columbia Oil and Gas Commission (BCOGC) has estimated that 20% of the water used in hydraulic fracturing comes from reuse of flowback water (Campbell and Horne, 2011). In summer 2010 parts of northeast B.C. experienced "persistent and severe summer drought" prompting the BCOGC in four river basins in the Peace Region, to place a moratorium on withdrawals of surface water for several months (Campbell and Horne, 2011).

2.3 Environmental Issues with Hydraulic Fracturing Fluids, Flowback and Produced Water

The composition of the chemical component of hydraulic fracturing fluids has been controversial as until recently the companies that manufacture fracturing fluid components have insisted the exact composition was proprietary. Over the last year or two between voluntary disclosure and state based disclosure laws the details of the composition of the chemical components of fracturing fluids are becoming known. These chemicals fulfill a variety of functions (Table 2): friction reducer; biocide (such as bromine, methanol or naphthalene prevent bacterial growth from clogging the fractures); scale inhibitor (such as hydrochloric acid or ethylene glycol to prevent precipitation of mineral such as carbonates from flowback and produced water); corrosion inhibitor (to prevent corrosion of steel casing and other metal components); clay stabilizer (minimizes swelling of expandable clay minerals); gelling agent (helps suspend proppants in the fluid during flow into the induced fractures); surfactant (such as butanol or ethylene glycol monobutyl ether (2-BE) to promote fracturing); and cleaner (such as hydrochloric acid to dissolve debris from drilling and the fracturing processes). The Environmental Impact Statement prepared by NY New York State (2009) includes a compilation

from Material Safety Data Sheets of 260 chemical compounds in the 197 products that companies submitted to the NYSDEC. The total number of different chemicals that have been used in the past is now known to be even larger than thought. Recently a congressional committee report has concluded that from 2005 to 2009, the 14 industry service companies have utilized over 2,500 products containing 750 chemical compounds.

The degree of danger to the environment from these chemicals is highly controversial. The concentrated form of the additive is an industrial strength chemical mixture. Recently in response to state based disclosure laws and regulations the chemical composition of fracturing fluids is becoming public knowledge. Three million gallons of hydraulic fracturing fluid "with 0.44% additives, will contain over 13,000 gallons of chemicals (including 3,300 gal of acid and 30 gal of biocide)" (Soeder, 2009). This mixture, if spilt and drunk by cattle (to quote a real example) is deadly.

The point in time when flowback effectively ceases and produced water from the formation dominates has been the subject of controversy. Some have suggested flowback be defined by monitoring certain chemicals in the fracturing fluid, others have used salinity or TDS as a measure, and some have added tracer chemicals to the fracturing fluid and measured their concentration in the water being returned. Unfortunately these approaches in most cases give very different answers for the same well. Siegel and Kight (2011) have noted that each shale gas play has a distinctive "halogen fingerprint". They suggest that flowback water can be identified from halogen chemistry, such as the Br to Cl ratio. The volume of injected water returned as flowback (estimated by using the variation in TDS to calculate a mixing relationship between the fresh injected water and a saline formation water component varies somewhat from well to well, but varies significantly between different shale plays. Overall it appears that 20 to 80 per cent of volume of water injected remains trapped in the subsurface. The factors controlling the relative volume of water returned from shale play to shale play are not understood however this percentage can play a key role in many shale plays in controlling the water usage. With high rates of recycling of flowback water taking place in some shale plays (see below) shales with high rates of return of relatively fresh flowback water may have lower overall water intensity than those with low returns.

Table 42. Flowback volume characteristics.

	Frac Water Volume (Mgal)	Flowback @ 10 Days (Mgal)	Ultimate Produced Water (Mgal)	Recovery Ratio
Barnett	3.8	0.6	11.730	3.1
Haynesville	5.5	0.25	4.475	0.9
Fayetteville	4.2	0.5	0.980	0.25
Marcellus	5.5	0.5	0.700	0.15

Source: M. Mantell, GWPC Annual UIC Conference, Austin, TX, January 26, 2010

Flowback waters contain some or all of the following: (1) sand and silt sized particles (from the producing formation or produced proppant material); (2) clay sized particles that remain in suspension; (3) oil and grease components, typically of anthropogenic origin, related to oils from compressors and drilling equipment; (4) water soluble organic compounds from the fracturing fluid additives and potentially extracted from the producing formation (including from the natural gas and condensate fractions in pore spaces); and (5) dissolved inorganic components (typically referred to as Total Dissolved Solids or TDS), apparently largely reflecting the brine like nature of the formation water in gas shale reservoirs. The chemistry of flowback and produced water gives us the most tangible estimate of the chemical makeup of the water that could potentially leak from the well after the hydraulic fracturing of the well is completed.

As flowback continues the total dissolved solids (TDS) of the fluids returned increases. Typically flowback water becomes higher in sodium, calcium, magnesium and chloride ions though the exact chemical makeup varies between different shale plays. Ba and Sr concentrations are unusually high in the flowback water in some shale plays such as the Marcellus. It is interesting to note that such high Barium contents can only occur if SO4- ions are low in concentration due to the low solubility of BaSO4 (Barite). The average chemistry of flow back water varies considerably between different shale plays. As summarized by Gaudlip (2010) the average TDS of flowback increases from 13,000 ppm for the Fayetteville shale, to 30,000 for the Woodford shale, to 80,000 for the Barnett shale, to 120,000 pm for the Marcellus shale. This sequence does not correspond to the relative depth of these reservoirs and is presumably controlled by the nature of formation water, in the shale.

Currently the factors controlling the chemistry of flowback waters appear to be only partially understood. Although many researchers appear to either explicitly or implicitly assume that flow

back water are simply mixtures of injected water with water from the formation itself, a number of industry experts have pointed to evidence of geochemical interactions in the reservoirs playing a role in the chemistry of water returning to the surface. Engel et al. (2011) have pointed to a "1.2‰ increase in δ18O between the hydraulic fracturing fluid and day 1 flowback" that they found followed by "much smaller (<0.2‰) shifts in subsequent [days] samples", that they interpret as indicative of water-rock interaction, particularly in the first day. This observation is probably explained by the dissolution of new surfaces created and damaged by the hydraulic fracturing process.

Kirby et al. (2010) in a study of flowback water from 5 wells in the Marcellus Shale play found that the pH ranges from 5 to 8 with total dissolved solids ranging from 1,850 to 345,000 mg/L (which they note is an order of magnitude more saline than seawater). They suggest that "much of the alkalinity" in the flowback water represents "naturally-occurring organic acids" and not HCO3-. In Marcellus flowback water Ba and Sr have a large range in concentrations with values a high as 26,800 and 5,230 mg/L, respectively (Kirby et al., 2010). Thermodynamic analysis using PHREEQC by Kirby et al. led to the conclusion that Ba and Sr concentrations are consistent with complexation by organic anions.

On a regional scale the chemistry of flowback water with the Marcellus shale shows considerable variability. Kirby et al. (2011) using a larger data set of chemical analyses of Marcellus flowback water samples have presented contour maps of concentrations of Sr, Ba, Li, U, Fe, and Zn (amongst others) that show for much of Pennsylvania the distribution of these elements in flowback water is distinctly heterogeneous. Kirby et al. (2011) also used this data set to examine the relationship between TDS and concentrations of a range of elements in flowback water. They showed that Sr concentration of flowback water is a linear function of TDS as TDS increases to approximately 100,000 ppm. At higher levels of TDS, Sr values increase at a higher rate as TDS increases. The most plausible interpretation of this data is that initially Sr concentrations are a product of linear mixing of fresh flowback water and in-situ formational brine. With increasing time water-rock interaction appears to become sufficient such that the Sr values become higher than predicted. The higher Sr values are likely the result of dissolution of a mineral such as calcite. This interpretation may perhaps be supported by Sr isotope data presented by Avner (2011) that shows that the initial Sr isotope ratio of flowback for the first five days of around

0.7110 changes to values of approximately 0.7112 at 15 and 20 days after the initiation of flowback.

Recent geochemical studies of Marcellus shale flowback water (Siegel and Kight, 2010) has shown Br/Cl ratios that clearly reflect the strong influence of what they identify as "Appalachian Basin brine" rather than an imprint from the dissolution of halite crystals in the Marcellus shale as proposed by Blauch et al. (2009). Siegel and Kight pose an important question based on their interpretation of the geochemical data that is do the fractures created by the hydraulic fracturing event extend beyond the low permeability Marcellus to tap brine fluids from more permeable brine filled formations. Or does the Marcellus shale contain, what they refer to as, "[a yet unrecognized] disseminated brine".

The nature of the organic chemicals in flowback waters are of considerable concern both in terms of understanding what chemicals present in the injected fracturing fluids are being returned and also what water soluble organic compounds from the shale may be present. Unfortunately only limited information is available on the nature of these chemicals and how they change over time after the hydraulic fracturing event. Acharya et al. (2011) show profiles for the hexane extractables and TOC for the flowback waters for a well from the Woodford Shale Play. Over the first two days they found high initial values for hexane extractable organics followed by a sharp decrease by the third day.

Struchtemeyer and Elshahed (2012) have studied the microbiological properties of hydraulic fracturing and flowback waters from two new gas wells in the Barnett Shale. Their study concluded that the biocides added to the fracturing fluid failed to kill all the bacteria. However based on r RNA diversity analyses, Struchtemeyer and Elshahed (2012) concluded that the microbial communities in the flowback water were "less diverse and completely distinct" from the microbial communities in injected fracture fluids. They further concluded that the microbial communities in the flowback water are "well adapted to survive biocide treatments and the [in situ] anoxic conditions and high temperatures" in the Barnett Shale. The implications of the discovery of microbial communities in this shale gas reservoir and flowback what remain to be assessed.

Another environmentally important component of flowback and produced water is NORM (naturally occurring radioactive materials) which are elements extracted from the shale and/or present in the formation water, brought up during flowback and in produced water. Each shale play appears to have a different pattern and range of levels for NORM. Uranium accumulates in anaerobic basins fixed by organic anionic complexes and Bank (2011) has shown that Uranium concentrations in Marcellus core samples are strongly correlated with organic carbon content. In a number of geographically diverse Marcellus shale cores studies by Resnikoff (2010) and Bank (2011) Uranium concentrations fell in the same general range between approximately 10 and 90 ppm. Uranium can be mobilized (under low pH conditions) by oxygenated fluids if these fluids are capable of oxidizing the organic component of the rock. Fortunately the fracturing fluids have a weak oxidizing capacity and are only mildly acidic (and the pH measured in flowback water is close to neutral as shown by data in Acharya et al, 2011). As a result the concentration of Uranium in flowback water is very low. Rowan et al. (2011a) have characterized the nature of Uranium in flowback as virtually absent. This they note "reflects its low solubility in the reducing environments at depth that characterize most oil and gas reservoirs".

The existence of radioactivity in flowback water has been a major concern of environmental groups, particularly in the Marcellus shale play. The most common naturally occurring radioactive material (NORM) constituents in flowback and produced water are Radium 226 (from decay of Uranium-238) and Radium 228 (from the decay of Thorium-232), which occur in the form of Ra2+ cations, present in aqueous solution in concentrations from zero to a thousand pico-curies per gram (1,000 pCi/L is equivalent 1 ppb Ra-226). Such concentrations are typically not a hazard except when concentrated by the precipitation of carbonate or sulfate scale. For example precipitation of barite scale concentrates Ra2+ as it substitutes in the sulfate mineral structure for Ba2+. Scale precipitates typically accumulate as inside pipes, storage tanks, and other well-head equipment that the flowback and produced water flow through. Exposure to radioactive scale is most likely when repair work is performed as exposure is only likely when equipment is opened, and exposure to the general public from scale deposits is highly unlikely. Shale gas wells are probably too new to have built up appreciable scale however a survey of older oil and gas wells in Pennsylvania may give some idea of the future NORM radiation from scale (probably a lower bound). The PA DEP from 1991 to 1995 conducted a survey of

radioactivity of NORM contaminated scale in Pennsylvanian oil and gas well head equipment (PADEP, 1995). Out of 400 well sites surveyed, 60 percent had radioactivity reading at or below background levels; 34 percent had levels under 10 micro R per hour and 3 percent had values from 11 to 20 micro R per hour and 2 percent were in the range 21 to 50 Micro R per hour (PADEP, 1995). Two samples had a higher radioactivity of 54 and 193 Micro R per hour. Only these two samples were viewed by PADEP as of regulatory concern. The USGS has expressed some skepticism regarding the PADEP survey, noting that "the time between hydrocarbon production and sample collection is unknown" and that "brines that accumulated in open pits presumably would have been subject to evaporation and (or) dilution by rain" (Rowan et al. 2011b). However the issue of greatest concern in the PADEP study was the radioactivity of scale deposits and these data are not impacted by these concerns. Engel et al (2011) presented data for flowback water from the Woodford shale that show a decrease in ratios of Ra-228 to Ra-226 with time to <0.5. These low, late-stage ratios were interpreted as reflecting U-rich source for the water, similar to that of the Marcellus shale. Low-TDS waters from the Woodford shale have values for NORM values that range from less than 20 to 500 pCi/L and do not pose any health or safety issues.

2.4 Disposal, Recycling and Reuse of Fracturing Water

Initially when gas shale drilling and production was initiated in Texas disposal of flowback and produced water was disposed of exclusively by injection into deep saline reservoirs into Class II disposal wells (permitted by the RRC in Texas under the Underground Injection Control program of the Safe Drinking Water Act). The Barnett Shale play is particularly fortunate because it is underlain by the Ellenberger Limestone at depth of around twelve thousand feet. In Texas there are over 12,000 Class II salt water disposal wells. Even with these large numbers of disposal wells in Texas, construction of new wells closer to the shale gas drills sites has been common to lower truck traffic and costs. As the areas of shale gas production spread though Texas, Louisiana (over 2,800 Class II wells) and Oklahoma (over 2,800 permitted wells) disposal via injection wells continued reflecting the widespread availability of such wells in these states (GWPC, 2009; ALL, 2009). Again if these disposal well sites are not close to the current area of drilling, extensive transport by tanker trucks will be required with inherent risks of accidental

spills. As a shale play matures there is a financial incentive to develop pipeline networks facilitate transporting flowback and produced waters to disposal sites.

Recycling and reuse are terms often used interchangeably by companies; however it is useful to draw a distinction between the two. In this paper recycling is defined as when flow back or produced water is treated such that the water is returned to a condition that it could be legally discharged into surface water (or at least into a municipal water treatment plant. That is the water that resulted is fresh water. Reuse is defined as taking flowback water, and after minimal treatment such as filtering out particulate and clays, directly mixing it with fresh water for use in fracturing. Recycled water may be used for fracturing or could be used for other purposes. Acharya et al. (2010) have noted that flowback water with TDS less than 45,000 ppm TDS, suitable for treatment using reverse osmosis membranes, are typical of: the Fayetteville Shale; the Woodford Shale; and over half of the Marcellus shale in NY State, but not in Pennsylvania. The flowback water in the Barnett, the Haynesville, and the Marcellus Shale in Pennsylvania and West Virginia require some sort of distillation approach. Gregory et al (2011) in a recent review of the water management challenges facing the shale gas industry, particularly in Pennsylvania, have discussed a number of new strategies and treatment technologies for recycling of flowback and produced water. The extent to which these approaches get used in the future will depend in large part on the cost of other disposal options and the feasibility of simply reusing the water.

The Barnett Shale play, having by far the longest production history, has the longest history of recycling and reuse. Many of the recycling and reuse strategies now being used in other shale plays were either developed or first tested in the Barnett shale play. Limited reuse is done in the Barnett when suitable infrastructure is available by taking the early fraction of flow back with lower salinity and mixing it with fresh water for the next fracture job. Multi-well pad drilling is particularly appropriate for this approach. Ewing (2008) provided an early description of Devon's recycling efforts in the Barnett. In 2005 treatment of 7.3 million gals of flowback water produced 6 million gals of "fresh" water. From 2006 to 2008 the amount of water treated increased from 65.4 to 210 million gals, all with a fresh water recovery of just over 80%. In 2008 the cost of processing 210 million gals was $874,552, with additional costs of $491,512 for trucking and $135,590 for disposal of 67,795 barrels of hyper-saline concentrate (Ewing, 2011). The cost of water treated was $4.43 per barrel; however as the system produced water the

company valued at $366,091, the net cost was $3.35 per barrel of water treated. As of March 2008, 90 to 100 percent of Devon's flow-back water was being treated and recycled (FWBOG, 2008). Today Devon's treatment and recycling program in the Barnett continues even though injection in disposal wells would be more cost effective. Ray (2011) quotes Devon's estimate that they "recycle about 85-percent of the water that comes up from the well". Evans (2011) reports that "Devon is the only company recycling water in the Barnett Shale". Certainly other companies are employing reuse strategies. In the Barnett Shale play, reuse and recycling has largely been limited to a fraction on the order of 5% of the total water production (Rassenfoss, 2011), in large part because of the wide availability of injection wells into the underlying Ellenberger formation.

In the Haynesville shale play, recycling of flowback and produced water has not been practical because of the limited and erratic quantities of water returned and its high salinity (Nicot and Scanlon, 2012). Similarly, reuse has been minimal in large part because of the low quality of even the early flowback water with high TDS, and high concentrations of particulates. In addition the flowback water has a low volume compared to the injected volume. Disposal through injection wells has been the method of choice. Recently operators in the Louisiana portion of the Haynesville have been trucking flowback water to Texas as a result of a new law in the state placing lower limits on the maximum injection pressure in Class II disposal wells (Bruyninckx, 2010). Unfortunately a higher risk of road accident related spills may be the unintended consequence of this regulatory change. Bruyninckx (2010) also points out that forthcoming rule change will necessitate a higher level of recycling or reuse in Louisiana.

In the Fayetteville shale play that developed in Arkansas reuse and recycling is enabled by the generally good quality of the flowback which is low in TDS (10,000 to 20,000 ppm) and chlorides in comparison to other shale gas plays (Veil, 2010; Mathis 2011). As a result, approximately 80% of initial flowback water each well (on the order of 250,000 gallons) can be reused. Reuse makes up approximately 6% of the total water used for fracturing a well (Mathis, 2011). Until recently more saline flowback and produced water from the Fayetteville play has been disposed of into a number of Class II saline injection wells drilled by the gas companies within the local area. Several of these wells were recently shut down by regulators and the operators in the play are now moving to treatment and recycling options.

When the Marcellus shale play was initiated, there were only eight permitted Class II disposal wells in Pennsylvania (one commercial well and seven private wells not permitted for Marcellus wastewaters), seventy such wells in West Virginia, and six private wells in New York State (ALL, 2009). Drilling new disposal wells in Pennsylvania was problematic as the existing wells had relatively limited injection capacity and the geology is largely not conducive to the drilling of cost effective disposal wells. This necessitated a change in disposal strategy by the shale gas companies as they began operations in Pennsylvania. The option of choice was disposal at municipal waste water treatment facilities. These facilities are not designed to treat the high salinity water. Effectively they only achieved dilution before discharging into surface water. These facilities soon became insufficient deal with the volumes of fluids being produced by Marcellus drilling activities. Acting on complaints from environmental groups regarding surface water pollution, regulators moved to stop this form of disposal and at present flowback is either partly treated and reused, or trucked out of state to saline water disposal wells, or sent to licensed saline waste water treatment plants. Depending on the company somewhere between 75 and nearly 100% of flowback water is being filtered and simply treated before being mixed with fresh water to supply the next fracturing job (Rassenfoss, 2011). This reuse makes up typically about 10% of the requirements for fracturing a well. Saline produced water is largely being sent to out of state disposal wells. Questions have been raised by researchers at Texas A&M as to whether the filtering techniques being applied to flowback water before reuse is adequate to remove sufficient particulates that this component will not cause a later production issue. Rassenfoss (2011) notes that trucking produced water to the nearest cluster of disposal wells in Ohio (a six hour drive from eastern Pennsylvania) costs about $4 per barrel of water for transport and another $1.5 to $2.0 for disposal. These costs can be compared with the cost of desalination treatment which Rassenfoss (2011) reports is around $7.50 for more saline water. So the desalination cost in the Marcellus play appears to be close to the cost of using out-of-state disposal wells. By June 2010 PADEP had permitted 31 facilities capable of treating flowback and produced water, however comparative cost is so far keeping the percentage of water being treated small (Rassenfoss, 2011). This may be because these plants are not integrated into a network of dedicated pipelines and storage impoundments designed to supply future fracturing operations.

3 Noise Pollution

Noise pollution is not only annoying, it can also have impacts on general health and wellbeing (Stansfeld and Matheson, 2003; Hygge, 2002). Drilling gas wells is noisy at least for several weeks at the beginning of the process. The use of large compressors and diesel electric generators are perhaps the main noise problems. Noise levels a logarithmic scale with units of decibels (dB). The loudness of sound doubles with every increase of 10 dB in sound pressure. For comparing the impact of noise on humans the dB level is an inadequate metric and a weighted sound level (dBA) is used to adjust a linear noise spectrum to better reflect the average response of the human ear. Today dBA levels as used to compare real noise to regulatory requirements such as a municipal noise ordinance or OSHA regulation.

Ambient noise levels vary considerably between day and night and between rural and urban areas. Night-time ambient noise levels in residential areas can be as low as 35 dBA. In Cities ambient noise levels can vary considerably with location and noise ordinances typically require at least a 24 hour continuous noise survey prior to drilling or building of a compressor station. Before drilling was permitted in Fort Worth a 24 hour sound survey was done at four proposed drilling sites (Behrens, 2006). This study found that typical day time sound levels (7am to 10pm) ranged from 54 to 67 dBA whereas night time levels (10pm to 7 am) varied from 48 to 62 dBA. In predrilling sound studies in more suburban settings to the west of Fort Worth, Behrens (2006) found average, ambient sound levels in the day varied from 59 to 66 dBA whereas night averages were 48 to 57 dBA. Such surveys provide a baseline for compliance and noise mitigation. The typical standard nationally ordinances regarding transient or temporary operation such construction is that sound increases above ambient are limited to 5 decibel dBA daytime and 3 dBA night time. Some municipal ordinances are more stringent with a 2 dBA limit. As studies have shown that most people cannot distinguish between noise levels until there is a 3 dBA difference (WSDOT, 2012), such limits should be more than adequate.

The Bureau of Land Management (BLM, 2000) has compiled measurements on noise levels 50 feet from unmitigated gas operations as: well drilling - 83dBA; produced water injection facilities - 71 dBA; and gas compressor facilities - 89 dBA. Behrens (2006) reported measurements of noise in various areas of a gas drilling rig 10 feet away as: diesel generator

engine, 100-102 dBA; running casing, 102 dBA; and on the rig floor noise averaged 85 to 105 dBA (where the 105 dBA measurement was from brake operations). He further noted that the average drilling sound levels at 200 feet from the drilling rig was 71 to 79 dBA with brake noise audible up to 1000 feet away. Noise measurements around gas well drilling operations in the Fort Worth area suggest that unmitigated increases in ambient sound levels are on the order of 20 to 25 dB(A) at 200 feet from the rig in the city. To put these values in context, a general rule of thumb (LACP, undated) is that noise from point sources decreases with distance by 6 dBA for every doubling of distance for hard surfaces (bare soil, gravel, concrete) and 7.5 dBA for soft surfaces (grass, vegetation). These values vary with topography, wind speeds and presence of tall barriers such as trees. So one would expect, unmitigated rig noise would be largely attenuated within 1,000 feet in a city setting (similar to those tested in Fort Worth by Behrens (2006) and by 1,200 feet in a quite rural, grassland setting. Clearly these estimates are only rough approximations and will vary up and down with topography and existence of barriers such as trees. Unless the aim is to effectively ban drilling, a 1,000 foot set back from receptors rule for an urban or city environment is not be practical, therefor noise mitigation is essential.

In urban environments, multiple strategies are used to mitigate various noise sources associated with shale gas drilling and production. Tall, plastic, sound-barriers (acoustical walls) are cost effective strategies that can are used to minimize these disturbances. At two hundred feet from a rig surrounded by an acoustical wall noise was measured as 64-68 dBA (compared to 72-77 without the wall, and at 500 feet noise was 53-56 dBA (compared to 61-66 without the wall) (Behrens, 2006). Similarly, using shrouds to mitigate brake noise results in noise levels of 65-70 at 200ft from the sources (compare to 72-77 without mitigation), and levels of 53-56 dBA at 500ft (compared with 61-66 dBA unmitigated). Additional approaches to mitigate sound include using blankets around engines, installing mufflers, noise control pipe wraps, baffles, sound deadeners, air-line silencers, and complete sound adsorbing buildings for reducing noise from compressor stations.

Noise in a conventional drilling rig comes from three main sources: the diesel generators that power the rig; the braking mechanism (part of the hoisting system); and handling drilling pipe. Some companies have developed low noise rigs based in minimizing all three of these noise sources. The actual hydraulic fracturing process can be noisier than drilling when utilizing low

noise drilling rigs. Using a combination of these approaches, best practice noise suppression on drilling rigs can get day time noise levels down to 59 dBA and night time levels to 51 dBA. These noise levels are at, or below, the equivalent average, ambient noise measurements in the city of Fort Worth and the suburbs by Behrens (2006).

Before any drilling on a specific drill pad begins, the City of Fort Worth's noise ordinance requires a 72-hour sound survey (which must include one weekend day). The purpose of this survey is to establish the typical average ambient sound levels are in an area. This survey is used to determine the permitted day and nighttime sound levels. These levels cannot be exceeded by more than 5 decibels during the day and by 3 decibels at night (Percival, 2009). Fracturing is allowed to be 10 dBA over the ambient level. The well operator is held responsible for meeting these requirements at the closest receptor defined as the property line of the closest residence or a protected structure such as a church or school. Avoiding noise in schools is particularly important as it has been shown to have a negative impact on the cognitive performance of schoolchildren (Hygge, 2002).

Industry best practice is to install sound meters on all drill pads, compressor stations etc., such that the site is connected by cellular phone or Wi-Fi to record sound levels 24 hours a day. When an excedence of permitted sound levels is detected sound engineers investigate to seek the source and report not only the cause but also what steps have been taken to prevent a recurrence (Percival, 2009). Behrens (quoted in Percival, 2009) notes that "maybe 75 percent of the exceedances we see in our continuous monitoring during drilling are generated from sources other than the drilling activity".

One aspect of noise pollution that has been not studied extensively is the impact on fauna in rural woodland settings. Francis et al. (2009) studied the impact of gas compressor noise on birds among natural-gas extraction infrastructure within woodlands of northwestern New Mexico. They concluded, in contrast to previous research that identified reduced bird densities as a consequence of road noise, that "no difference [exists] in community nest density between treatment [sites near gas compressors] and control sites". However they noted that bird species that are intolerant of noise may face higher nest predation rates than species that can inhabit noisy areas. Francis et al. (2011) have studied further studied habitat use and nest success of bird species impacted by chronic, natural-gas compressor noise, again in woodlands in northwestern

New Mexico. Compressor noise impacted over 80 percent of the study area and "occupancy of each species was approximately 5% lower than would be expected without compressor noise". The flycatcher nest success was 7% higher as a result of less predation in noisy areas. Deployment of sonic walls around compressors could reduce the noise impacted area by 70% and "maintain occupancy and nest success rates at levels close to those expected". They concluded that without noise-reducing walls, the industry's soundscape footprint will grow as more wells are developed and that to "maintain some semblance of the natural soundscape" mitigation by sound walls is required to "minimize the spatial distribution of this industry's impact on natural communities".

Other studies have been published on impacts on bird species of gas production, but have not specifically considered noise. In the Upper Green River Basin, Wyoming from 2008–2009, Gilbert and Chalfoun (2011) evaluated the abundance and species richness of songbirds as a function of the well density at two natural-gas fields, and one oil field,. There was no particular trend in species richness as a function of well density. However they found that increased well density was correlated with significant decreases in abundance of Brewer's sparrow and sage sparrow particularly in the Jonah natural gas field. Vesper sparrows also decreased with higher well density. The abundance of horned larks increased with well density in the Pinedale Anticline natural gas field. Gilbert and Chalfoun (2011) suggest that regional declines of certain songbird species "may be exacerbated by increased energy development". As noted above these are broadly similar to the impacts on bird species by noise from distributed gas compressors (Francis et al., 2009; Francis et al., 2011)

Drilling and hydraulic fracturing is a temporary, transient activity typically lasting a few weeks. Noise can be successfully mitigated down to measured ambient sound levels in suburban and city environments. Noise ordinances such as those implemented in Fort Worth appear to be effective in gaining public acceptance of drilling activity as well as allowing industry to mitigate noise in a cost effective way. Earth Works (EW, undated) has proposed that a noise limit of 45 dBA at night for urban areas be implemented for shale gas drilling. Although Earth Works suggest that "there are several jurisdictions that require oil and gas operators to meet a 45 decibel level during the night-time, in residential areas" they do not identify the locations of these localities.

Considering the ambient noise level measurements in city and urban environments in Fort Worth documented in Behrens (2006), such a proposal doesn't make sense.

4 Risk of Surface Spills

The drill pad is a locus for potential spills and leaks both from impoundments, storage tanks, and from surface blowouts or leaks from the wellhead. The New York State Water Resources Institute at Cornell note that such spills "may result from accidents, from inadequate management or training, or from illicit dumping" (NYSWRI, 2011). Hydraulic fracturing chemicals and flowback water present a more significant risk above ground than they do in the deep sub-surface. This is particularly the case if the fracturing chemicals are in their concentrated form before dilution in large quantities of water. These risks can be mitigated in part if the volume of chemicals stored at multi-well pads is reduced by either offsite premixing of fracturing fluids and just-in-time-delivery. Flowback water is typically pumped into temporary storage in an impoundment before transport by truck or pipeline to the next well pad for reuse, to treatment plants, or disposal sites. Trucks hauling hydraulic fracturing chemicals, flowback, and produced water can be involved in accidents resulting in spills. Similarly transporting flowback or produced water to injection or treatment sites, by both pipeline or tanker truck can result in accidental spills. Leaks in pipelines can be problematic as it may be some time before the leak is discovered.

For any spill three characteristics are important: the degree of containment of the spill; the volume of the spill; and its toxicity (Riha and Rahm, 2010). By definition a contained spill poses no to human health and/or to ecosystems. The toxicity of the spill depends not only on the nature of the chemicals spilled but also their concentration. Containment is the key to preventing impacts to ground or surface water from spills. Without effective containment, highly toxic surface spills of any volume are problematic if the fluids can leak into ground or surface water (NYSWRI, 2011) and there are exposure pathways linked to risk receptors such as animals and humans. In contrast a successfully contained spill should pose little threat to the environment, unless there are toxic air emissions.

An important mitigation approach is to establish secondary containment for fuel storage containers and areas where tanker trucks load and unload. Tanks with fracturing fluid concentrate should also be inside lined secondary containment areas. As outlined by Hull (2010) best practices for "environmental containment" to mitigate surface spills on pads include laying

down a "sandwich" of interlayered felt and plastic to create a "leak-proof continuous barrier. When industry uses that term containment means that the spill is prevented from leaking into surface or groundwater and is constrained such that it can be readily cleaned up. Hull describes a perimeter barrier as a "10 inch silt sock…. often accompanied by an additional barrier with memory foam". Hull suggests that if leaks occur "vacuum trucks scour the surface of fluids for safe disposal". Anecdotal evidence from environmental blogs and news reports suggests that this kind of containment approach is not standard with many gas companies. Gravel pads, dirt berms, trenches, plastic sediment fences etc. are perhaps more common. Other best practices include developing spill response plans, which include transfer and disposal procedures (PIG, 2012). Having a contingency plan, necessary supplies and equipment for spill management (as well as a well trained staff can not only prevent negative environmental impacts it also can keep downtime to a minimum (PIG, 2012). By far the most effective approach to mitigating the risk from surface spills is to avoid the use of toxic chemicals by using non-toxic fracture fluids. Spill management and remediation should be based on carefully thought out contingency plans that are developed jointly with local emergency responders and regulatory agencies. Rapid communication of the nature, volume, and toxicity of the spill is the key to effective emergency response.

Another potential source of leaks is the impoundments (typically lined, open-air pits) used at many drill pads to store water for hydraulic fracturing, and subsequently flowback and produced water. Lining of the pits is based on company policy and varying state regulation. As noted by Vaughn and Pursell (2010) even lined pits can leak if the plastic liner tear or the pit overflows due to excessive storm-water accumulation. Best practice is to use clay lined pits that are not susceptible to tearing. In contrast, Myer (2009) has suggested that water associated with hydraulic fracturing should be stored in "closed-looped steel tanks and piping systems" should be used for any centralized storage of flowback water" because "lined systems are subject to leaks".

Little information is available on the short and long term consequences of surface spills. Unfortunately the vast majority of regulatory reports on spill investigations associated with the Marcellus shale in Pennsylvania do not provide any context that would allow insights into the spills potential for environmental damage or whether the spill was effectively remediated.

One experiment has been performed by Adams (2011), just over three hundred thousand liters of flowback water was spread over a 0.20-ha test area on the Fernow Experimental Forest, West Virginia, characterized by mixed hardwood forest. Other than the fact that the flowback had a pH of 7.8 no chemical data on the flowback water was gathered. During the application of the fluid, ground vegetation suffered extensive damage and destruction, followed about 10 days later by premature leaf drop by "over-story trees". After two years the mortality rate of trees within the plot was 56% with America Beech (*Fagus grandifolia* Ehrh.) being the most impacted tree species, and Red Maple (*Acer rubrum* L.) was the least impacted. May reported that concentrations of sodium and chloride soil immediately increased 50-fold and then declined over time (as did soil acidity). Given the available data it seems likely the high salinity of the flowback water was responsible for the underbrush and tree mortality. This study does give some idea of the potential consequences of large, unremediated spills of flowback water.

The key question is how often do surface spills occur and what is the nature of the environmental consequences of these spills (and the result of remediation efforts). Regulatory agencies either do not collect this information or do not make it publicly available in a form readily accessible. Perhaps the best attempt at providing such information comes from British Columbia where accidents are rated on a scale of increasing environmental impact. In 2010 the agency reported one level 3 incident (involving serious impacts to the public and/or environment and resulting in immediate danger) and one level 2 incident (that may pose a major risk to the public and/or environment) (REFERENCE).

On a very positive note, some shale gas companies now provide statistics on volumes of their spills on their web site. Such statistics typically are general company-wide aggregates and lack details on impact/outcomes but they help with an emerging picture of risks from spills. For example the number of spills (of larger than a half a barrel of fluid) recorded by Talisman, have decreased from 415 spills in 2008 to 109 spills in 2010 (Talisman, 2010). The total spill volume recorded by the company in 2010 was 501 cubic meters (about 66% of these were hydrocarbon spills). The largest spill (as reported on the company web site) was in March 2010, from a shale gas drilling operation in Bradford County, Pennsylvania, where a large spill of diesel fuel leaked partly offsite into a field. 1,700 liters (450 gallons) was recovered and Talisman's environmental response crews remediated the impacted area (Talisman, 2010). The key outcome though was

that the company implemented a number of improvements to prevent future offsite impacts across their North American operations including installing plastic liners under drilling and completions sites, upgraded connector equipment to lower likelihood of leaks, and increased spill prevention training.

5 Environmental Impact of Blowouts

Blowouts are uncontrolled fluid releases that rarely occur during the drilling, completion, or production of oil and gas wells. A blowout occurs when fluid flows out of the well to the surface under pressure or flows into a subsurface formation. This can only occur after all the static and dynamic barriers put in place to prevent such an event have failed. Blowouts pose a significant safety hazard, and can result in environmental damages from the fluids lost from the well, resulting (in some cases) in substantial mitigation and remediation costs.

During drilling, blowouts can occur if unexpected high pressures are encountered. Blowouts can also be caused by mechanical failure of components such as valves. Some aspects of the drilling and completion of shale gas (and hydraulically fractured tight gas) wells present unique risks for blowouts. For example unexpected pressure bursts can occur during completions, particularly during drill out of plugs. Also unexpected and unpredictable pressures changes can be caused by nearby fracturing activity. The B.C. Oil and Gas Commission recently put out a safety warning following a series of incidents where evidence suggested that the hydraulic fracturing a well had resulted in establishing a connection with existing open fractures of an adjacent wells or in which during the drilling itself, the well intersected an existing open fracture.

Blowouts can be simply classified into surface and subsurface. Subsurface or underground blowouts are described by Tarr and Flak (2005) as "involve[ing] a significant down-hole flow of formation fluids from a zone of higher pressure (the flowing zone) to one of lower pressure (the charged zone or loss zone)". Tarr and Flak (2005) assert that underground blowouts are the "most common of all well control problems" and that "many surface blowouts begin as underground blowouts". Statistical information on t he frequency and consequences of underground blowouts are limited and the consensus in the technical literature appears to be that most go unrecognized or unreported. It should be noted that Tarr and Flaks observations may well not include any information from shale gas drilling.

In their training module on dealing with underground blowouts Smith et al. (undated) note that the consequences of such incidents range from being "indiscernible to catastrophic". Specifically they note that an underground blowout can result in "minor subsurface transfers of fluids that

may never be identified" or in fluids flowing to the ground surface where "a crater, a fire, loss of equipment, and sometimes loss of life may result".

The biggest problem with underground blowouts is our limited ability to understand what is happening in the subsurface during unexpected events (Grace, 2003). So for example when blowout preventers are activated when a pressure "kick" is experienced during drilling or well completion, the pressure surge though prevented from creating a surface blowout by the BOP could exploit weaknesses in the casing and cement resulting in an underground blowout that may or may not be recognized by the well operator in post-mortem examination of pressure and other records.

Several incidents of underground blowouts associated with shale gas wells have been identified by State regulators. In the Barnett Shale play the Texas Railroad Commission has determined that of twelve blowouts two were underground blowouts. Unfortunately in none of these cases is there sufficient publically available information to evaluate the causes or consequences of the blowout (see Duncan, 2012).

By far the most data and systematic analysis on blowout frequency and consequences is available from offshore oil and gas drilling (OGP, 2010). As this report notes there is no comparable data for onshore wells. This data set for offshore North Sea wells, suggests that blowouts related to drilling wells have a frequency of 6.0 x 10-5 per well drilled, whereas blowouts during completions at a frequency of 9.7x10-5 are more common whereas blowouts during wire-line logging are rarer at a frequency of 6.5x10-6 (OGP, 2010). The highest frequency of blowouts is associated with well workovers with a frequency of 1.8x10-4. As noted by Duncan (2012) the higher risk of workover operations is predicable in that workovers are required when there is a problem of some sort with the well.

The OGP report also separates out blowouts from "shallow gas wells" (which are actually events in any well being drilled, prior to the installation of a BOP). For "shallow gas" exploration wells the frequency of surface blowouts is 6 X 10-4 versus a frequency for underground blowouts of 9.8 X 10-4. Similarly for "shallow gas" development drilling the frequency of surface blowouts is 4.7 X 10-4 whereas the frequency of underground blowouts is 7.4 X 10-4 (OGP, 2010). So in each case the frequency of underground blowouts is higher than that of surface blowouts. For the

deeper data set (deeper in this context meaning after the installation of a BOP) no data is available for subsurface releases. In general it might be predicted that underground blowouts would be more prevalent after the installation of blowout preventers as long as the BOP works, unexpected "pressure kicks" will not result in a surface blowout but will stress the subsurface integrity of the well. It is not clear if regulators systematically conduct an investigation after neither any activation of the BOP system nor whether pressure records are examined to look for patterns indicative of underground blowouts.

Putting this information in the context of what is known of the blowouts associated with shale gas drilling Duncan (2012) concluded that in all likelihood that the number of underground blowouts is under reported (consistent with what appears to be the consensus of industry technical experts on this issue). For example in the Barnett Shale it might be expected that on the order of another 8 to 10 unde rground blowouts may have occurred. There is certainly no evidence that this is the case but the possibility of more widespread occurrence of underground blowouts should be carefully considered by both the gas companies and the regulatory agencies involved.

The potential consequences of underground blowouts depend largely on three issues: (1) the timing of the blowout relative to well activities (this will determine the nature of the released fluid such as pressurized fracturing fluid or natural gas); (2) does the breach of containment occur through the surface casing or deep in the well; and (3) what risk receptors, such a fresh water aquifers and water wells are impacted.

We do know that underground blowouts do occur in association with both wells that have been hydraulically fractured and were about to be fractured.

For a few underground blowouts (not related to shale gas drilling) at least some aspects of groundwater contamination have been investigated. For example Schramm et al. (1996) reported the underground blowout of Louisiana gas well resulted in transient pressurization of the shallow Wilcox aquifer. In response a number of surrounding water wells started spouting water. At the same time sand and formation water "created a crater around an old abandoned well south of the active rig and a collapse crater north of the rig". The company started an investigation of the nature and extent of groundwater contamination caused by the blowout which revealed minor

localized contamination by BETX. A more detailed study of the impact on groundwater of an underground blowout of a gas well was reported by Kelly and Mattisoff (1985). In 1982, a gas well in Ohio unexpectedly drilled into a shallow (~500 m), high pressure natural gas pocket resulting in an underground blow out. Kelly and Mattisoff (1985) describe gas "shot up the uncased wellbore" and invading shallow rock formations apparently transported through preexisting fractures. Within a few days vigorous gas bubbling was observed in water wells and surface water, and the floor of the basement of one house was uplifted several inches and cracked (followed by one meter depth of water. Soon thereafter authorities evacuated 51 families over an 11-km 2 area. A small fire and explosion did happen in one house, before the well was brought under control and capped a week later. Aeration devices were installed in water wells to vent natural gas. Eight months later water in four wells still had unsafe concentrations of gas.

6 Groundwater Contamination

The rapid expansion of shale gas drilling has coincided with a growing concern about the environmental impact of drilling amongst the general public and a specific concern regarding the contamination of domestic water wells. Complaints of contaminated water wells spatially associated with shale gas drilling have been ascribed by regulators to problems with inadequate well casing and or problems with the cementing of casing. It may be that contamination from surface spills and leaky pits is a greater risk; however there is essentially no information to test such a hypothesis. There are concerns that the high pressures required for hydraulic fracturing stresses flaws and weaknesses in the casing cement sheath related to well construction error, weaknesses in steel casing pipe, and/or problematic cementing.

Energy in Depth, a vocal industry funded group, has argued that the onus is on well owners and environmental activists to prove that shale gas is responsible for contaminating water wells. They assert that in 60 years of hydraulic fracturing "it has yet to be credibly tied to the contamination of drinking water". Some have suggested that conducting a test with hydraulic fracturing fluid tagged with a dye or some other tracer combined with test drilling to sample the overlying aquifers could be a definitive test of whether hydraulic fracturing does create conduits that result in contamination of freshwater by fracturing fluids.

In areas overlying gas shales, source rocks for methane it is not surprising that methane is widespread in porous sands at depths between the shale and the surface and in some shallow aquifers. In addition, methane from biogenic sources, from old, leaking abandoned-wells, and from leaking gas storage reservoirs have been documented. Although the Pennsylvania Department of Environmental Protection filed violations against gas companies that faulty well construction (cementing and/or casing) of shale gas wells has resulted in methane gas migration into the water wells. It is important to understand that this conclusion on the part of regulators in Pennsylvania does not constitute scientific proof. It does not even require that regulators believe it to be true as PADEP regulations state that the onus is on the drilling operator to prove that they did not cause the contamination by conducting pre-drilling water analyses of any water well within 1,000 foot of the proposed gas well and showing that the contamination was pre-existing.

In the absence of such proof, any contamination found in the well water is considered to have been caused by the drilling of the gas well.

Most but certainly not all of the complaints about groundwater contamination associated with shale gas activity come from rural Pennsylvania. Amy Mall of the Natural Resources Defense Council keeps a running and unfiltered compilation of well owner's complaints, all claiming that shale gas drilling activity has polluted their wells (Mall, 2012) and Pennsylvanian wells lead the list. Duncan (2012) has attempted to track down and evaluate information such as chemical analyses and regulatory agency reports relating to all of these incidents. These reports have a number of commonalties, the main one being that the well owners water suddenly changed color from clear to red or brown or grey (corresponding to an increase in turbidity or cloudiness). Typical contaminants reported are: iron and manganese (the two most commonly reported contaminants); sometimes bubbles of methane gas; sometimes benzene (and/or toluene); and sometimes (particularly in Pennsyvania) other elements such as strontium, and barium.

To put these issues in a proper context it is important to first understand the nature of water wells in rural areas, particularly the background levels of water contamination found in such wells unassociated with shale gas drilling. The best available data comes from Pennsylvania where Swistock et al. (2009) reported a survey of 701 private wells statewide. Only 16 percent of wells surveyed had a sealed, sanitary well cap. About 5 percent of the homeowner wells had both a sanitary well cap and evidence of cement grout around the well casing. Only a "handful" had apparently been grouted the entire length of the well (as is required in many states). Less than one third of the well owners had any awareness of water quality of their wells and with "the highest awareness occurring for… nitrate, pH, [and] bacteria". Although only 2 percent of the wells exceeded the 10 mg/L drinking water standard for arsenic, 89 percent had measurable arsenic levels below 6 mg/L, with high arsenic occurred mostly in northern Pennsylvania. Only eight percent of well owners whose wells tested as having elevated arsenic values were aware of the problem prior to the Penn State survey.

GWPC (undated) reviewed approximately 10,000 chemical analyses of groundwater from Pennsylvania water wells and compared to "existing ground water quality (Pennsylvania public drinking water) standards such as maximum contaminant levels'. This study found 10 to 25% of the samples analyzed exceeded the drinking water standards for pH, TDS, nitrate, iron,

manganese and turbidity. In the same study less than 1% exceeded the standard for sulfate, arsenic, and barium. The US Geological Survey (Low et al., 2008) has analyzed a considerably larger data set to the GWPC (nearly 25,000 wells and springs). Significantly they also found that "of the 4,528 samples collected and analyzed for volatile organic compounds [VOC's], 23.5 percent exceeded an MCL. Oram (2011) suggests that in Pennsylvania barium concentrations in groundwater above 0.5 to 1 mg/L would likely reflect impacts from long-time-scale mixing with "saline water", presumably brines migrating from deeper formations. He reports one water well that had a barium concentration "about 1.6 mg/L". He suggests that this well was by Marcellus Shale drilling or a surface spill of produced water but rather "the well was deep enough to permit the mixing of saline and freshwater". Oram (2011) also reports "a saline seep in Susquehanna County [PA]" with "barium levels of over 160 mg/L".

A common contaminant in drinking water wells is methane. In the past it has been assumed that such methane is biogenic coming from microbial breakdown of organic matter in the aquifer. Increasingly however analysis of methane in aquifers above gas shale reservoirs (such as the Marcellus in Pennsylvania and the Barnett in Texas), has proved to be of thermogenic origin and isotopically similar to the gas in the underlying shale. Examples of seepage of thermogenic methane into higher formations and ultimately into water wells are common in areas of Texas that overlay the Barnett Shale (Kornack and McCaffrey, 2011). Local residents and water-well-drillers in Hood County, Texas have reported that water wells in the area have been historically contaminated with methane (Montes and Chandler, 2011). Years before any shale gas drilling activity, water well drillers have recorded both intermittent and sustained (up to 122MCF per day) natural gas production from some of the water wells drilled in the area (Montes and Chandler, 2011).

Methane in water wells is so common in Pennsylvania that both the Pennsylvania State University Extension Service and the Pennsylvania Department of Environmental Protection (PA DEP) have for decades distributed pamphlets for home owners entitled "what do if you have methane in your water well" or some similar statement. The Pennsylvania Geologic Survey has a note on its web page that "in some areas of Pennsylvania (especially areas of coal mining and gas well activity), stray methane gas in the subsurface can be a hazard. Under certain conditions,

methane can migrate to private water supply wells and ultimately into a house or structure. Unmitigated, methane can build to explosive concentrations."

The USGS has done a study of methane concentrations in water wells in West Virginia years prior to shale gas drilling. Between 1997–2004 they sampled 170 residential water wells from 47 counties (White and Mathes, 2006), detected dissolved methane in 131 of these wells, with dangerous concentrations over 28 mg/L in 13 wells (about 8% of the wells tested) and another 13 wells with levels in the range 11.9 to 24.3 mg/L. White and Mathes (2006) assumed that the methane in these wells was coming from underlying coal mines, but this has not been scientifically established. Baldassare and Laughrey (1997) have plotted Hydrogen and Carbon isotopes of methane gases from both Pennsylvania coals and deeper thermogenic gases and shown that they are indistinguishable in these isotopic ratios.

More recently Boyer et al. (2011) have completed an 18 month study of water quality in 48 rural water wells specifically designed to evaluate water quality prior to shale gas drilling. This study found approximately "40 percent of the water wells failed at least one Safe Drinking Water Act water quality standard", most often for "coliform bacteria, turbidity and manganese, before gas well drilling occurred". Statistical analysis of post-drilling versus pre-drilling water chemistry did not suggest any significant correlation between shale gas drilling activity on nearby water wells, based on changes in levels of contaminants most abundant in the flowback water. Comparing levels of dissolved methane in the water wells sampled pre and post drilling, Boyer et al. found no statistically significant increases in methane or correlation to distance from gas wells. In plots of chemical components before and drilling presented by Boyer et al. (2011) and interested trend can be discerned. For most all components such as sulfate, hardness, sodium and strontium no systematic differences can be seen. However there are a number of wells that show significant increases in both iron and total suspended sediment after drilling. Duncan (2012b) has suggested that sudden onset of turbidity and water quality issues could be caused by disturbance of biofilms, corrosion products and sediment in water wells could be caused by pressure waves from drilling activity. In a provocatively titled presentation Eisner (2011) presented evidence that turbidity of water in domestic wells can be triggered by merely running several faucets to create unusually high pumping rates.

7 Impact on Landscape

Current practice is to drill multiple wells from a single pad to drain on the order of 0.386 square kilometers (640 acres) per pad. Howarth (2011) suggests that single a 2-hectare well pad and "up to 16 wells" can service "an area of up to 1.5 square kilometers". Sweet (2010) quotes a spokesman from Range Resources as saying that "You can develop 1 square mile [of subsurface field] and yet disturb only 1 percent of the surface". Prior to multi-well horizontal drilling from a single pad (typically involved 8 to 12 wells) the density of vertical well pads on the landscape was considerably higher. On the order of 1.5–3.0 ha of land is cleared to construct each multi-well pad (Entrekin et al., 2011). The construction of the pad site (and associated roads and infrastructure) can impact the quality of local streams and lakes by the discharge of sediment-laden water during rain storm events (Williams et al. 2008; Adams, 2010). In most cases shale gas drilling takes place in rural areas and accessing many drill pads sites requires constructed of new unimproved roads (Sweet, 2010). Road construction alone can have negative ecologic impacts (Ellis, 1936; Forman and Alexander, 1998) that can only be partially mitigated. Soeder and Kappel (2009) have noted that transporting water, well materials and heavy equipment to rural drill sites over dirt or gravel roads will lead to some degree of degradation of streams and watersheds sediment and chemicals from erosion and spills. State regulations controlling oil and gas activities have various safeguards in place designed to minimize surface impacts.

The detailed three year field study by Banks and Wachal (2007) on the impact of gas drilling on storm water runoff in part of the Barnett sale play in Denton County Texas is perhaps the first research to attempt to directly quantify the environmental effects of such activity. This study (reported also in Williams et al., 2008) set out to develop guidance on how to best regulate such activity in part through developing best management practices particularly to reduce sediment pollution. The annual predicted sediment yields from the two test sites in this study were 38.0 and 20.9 t ha-1 yr-1. In a study of three construction sites Daniel et al. (1979) after two years of monitoring estimated average sediment yield from the sites of was 17.5 to ha-1 yr-1. In a similar two year study of three residential construction sites Madison et al. (1979) estimated sediment yields of between 39 to 90 t ha-1 yr-1. This led Banks and Wachal (2007) to the conclusion that the sediment yields from natural gas well sites are similar to typical construction sites. Banks and

Wachal (2007) suggested that the most effective approach to erosion control focused on the most erodible parts of a hill slope. They recommend mitigation strategies based on use of seeding and filter strips, in addition to terraces, check dams, filter fences, and straw bales.

There is contradictory information on the overall impact of shale gas development on water quality is streams. In the Barnett shale play TCEQ has four monitoring locations (Denton, Dallas, Tarrant, and Johnson Counties Texas) in streams draining the area of most intense shale gas activity with long term measurements of TDS. None of these monitoring locations show any appreciable change in TDS between the years before and after shale gas drilling began (Nolen, 2011, quoting data developed by GSI Environmental).

The Nature Conservancy has significant concerns over the potential impacts of Marcellus shale gas drilling on the ecology of rural Pennsylvania and adjoining states. Watersheds with healthy eastern brook trout populations substantially overlap with projected Marcellus development sites. Those of Pennsylvania's watersheds still ranked as intact are concentrated in north central Pennsylvania where drilling activity may be intense. Johnson et al. (2010) note that almost one third of the species of concern to the Pennsylvania Natural Heritage Program "are found in areas projected to have a high probability of Marcellus well development", and that 132 of these species are globally rare, "critically endangered, or imperiled in Pennsylvania". Johnson et al. (2010) also suggest a number of best practices for developing shale gas infrastructure that they believe can considerably mitigate negative impacts on the land and ecology. One they suggest is relocating projected wells pads to open areas or "toward the edge of large forest patches". Their GIS study in the southern Laurel Highlands for example suggested that this approach could reduce the net area of forest clearing by 40 percent and interior impacts on forest lands by over a third (Johnson et al., 2010).

For the Marcellus shale play the Nature Conservancy has estimated that two thirds of the well pads will likely be constructed in forest areas (Johnson et al., 2010). They project that this will involve the clearing of 34,000 and 83,000 acres (depending on the number of wells per pad), with an additional 80,000 to 200,000 acres of habitat impacts due to new forest edges created pads and associated road infrastructure (Johnson et al.,2010). The Conservancy notes that although statewide, the cumulative forest clearing is less than one percent of the state's forests, clearing and fragmentation will likely have a more "pronounced" impact in areas with intensive

gas well development. As noted by Sweet (2010) keeping surface disturbance down to about one percent of area locally (rather than regionally) is possible using best practice that the gas industry has developed a figure lower than that assumed by Johnson et al. (2010).

The report by Johnson et al. (2010) was based on information on impacts from other areas and other industries. Recent research on measuring actual impacts from monitoring the effects of construction and operation of drill pads in shale gas impacted areas is just starting to become available. Frank Anderson, a Staff Scientist, at the Academy of Natural Sciences at Drexel University has examined the relationship of the density of shale gas well pads per watershed area on the ecology of nine headwater streams (tributaries of the North Branch of the Susquehanna River) located in part within Susquehanna County in northeastern Pennsylvania (Anderson, 2011; Mead et al., 2011). The sites were similar in characteristics, but differed in their well pad density. Three sites had high-density (0.75-2.38 wells/km^2) three had lower well densities (0.39-0.61 wells/km^2), whereas three sites have no drilling activity. Data from this preliminary study (Anderson, 2011; Mead et al., 2011) demonstrate an association between increases in natural gas well density with decreases in water quality indicators such as of stream water. Sites with high well pad density had stream water significantly contaminated with an average a 60% increase in specific conductivity of stream water compared with those at low well pad density sites. There is a correlated degradation of macro-invertebrate community, family richness (the number of macro-invertebrate families); and Shannon Diversity. Anderson (2011) concluded that "there were no statistically discernible differences [using a student t-test] between sites in catchments with low drilling densities and those with none". It is important to note that current industry practice of drilling from multi-well pads would give a well pad density of less than the "low density" test areas studied in their project. So based on the careful (but still preliminary) study reported in Anderson (2011) and Mead et al. (2011) it would be reasonable to conclude that only limited impact on the water quality and ecology of streams might be expected to accompany further development of the Marcellus shale play.

The DOE's National Energy Technology Laboratory (NETL) is currently sponsoring a wide range of research into understanding and helping to develop mitigation plans for the ecological impacts of access roads and drill pads (Hammack, 2010). For example: researchers at Penn State University are investigating better designs for dirt and gravel roads; researchers at West Virginia

University are investigating the possible impact of shale gas drill pads and roads on sensitive bird species; and Clarion University is studying the possible impact on aquatic life in streams, particularly macro-invertebrates.

8 Atmospheric Emissions

Air emissions related to shale gas production begin with dust and diesel fumes from road and drill pad construction activities and as well as truck traffic to and from the site. Emissions associated with drilling and fracturing activity include nitrous oxides, diesel fumes, volatile organic compounds (VOC), hazardous air pollutants (HAP as defined by EPA) such as methanol, and fine particulates or PM2.5 (defined by the EPA as particles less than 2.5 micrometers in diameter)mostly from engine exhausts and fugitive vapors from fracturing fluids. Depending on the composition of the gas coming from the shale reservoir VOC's are typically rich in the BTEX compounds (benzene, toluene, ethylbenzene, and xylene).

Methane, a powerful green-house-gas, is the dominant component of natural gas. Venting of natural gas may occur during the hydraulic fracturing process and flowback, although many gas companies use low emission completion equipment (sometimes called green completions) to capture and sell rather than vent or flare methane produced with water flowback. Fugitive emissions of natural gas come from leaks and in some cases pressure-relief venting valves associated with separators, condensate tanks, produced water tanks and so on. Some emission components including methane and short chain hydrocarbons (ethane, propane, butane) have little toxicity. Prominent VOCs in emissions from condensate tanks are longer chain hydrocarbons such as ethane, propane, n-butane, iso-butane, and pentanes.

Although the processing of natural gas is essentially confined from the well to sales, CH4 may be released as a fugitive emission from gas processing equipment, especially equipment in high pressure service such as pneumatic controls. Although the gas industry has an economic motive to minimize natural gas emissions to increase the amount of delivered product it is not yet publicly known to what extent best management practices (such as low emission completions, low-bleed gauges and valves and so-on) to reduce vented and fugitive losses of methane.

Of the common minor and trace gases sometimes present in natural gas hydrogen sulfide (H2S) is perhaps the most dangerous, being extremely toxic at relatively moderate concentration levels. Fortunately shale gas typically has negligible concentrations of H2S. If it does occur the gas industry has good technology to monitor and safely handle this gas. Flaring of natural gas, although a good thing for reducing GHG emissions, results in the production and emission of a

myriad of toxic compounds such as benzene, toluene, xylenes, polycyclic aromatic hydrocarbons (PAHs, including naphthalene), ethyl benzene, formaldehyde, and propylene. Flared gas at well sites is typically vented through a tall pipe and as the gas is under relatively high pressure the flared combustion products are imbued with a considerable vertical upward velocity so these gases will be more likely to add to regional rather than local concentrations of emissions. Another source of emissions in associated with shale gas production come from compressor engines (typically fueled by natural gas). The main emissions from compressor engine exhausts are nitrous oxides. Use of catalytic emissions controls has lowered emissions from these types of engines by a factor of ten to below 2 grams of NOx per horsepower hour. Other emissions from these engines include carbon monoxide (CO), PM2.5, as well as VOC, and HAP emissions.

Raun, L., 2008, Benzene Risk: Determining Carcinogenic Health Risk Concentration Levels for Benzene in Ambient Air at EPA, TCEQ and the City of Houston, Report prepared by City of Houston Mayor's Office of Environmental Programming, http://www.greenhoustontx.gov/reports/benzenerisk.pdf

EPA Clean Air Act Risk Range			Benzene (ppb) most protective end of toxicity range		Benzene (ppb) least protective end of toxicity range	
			$\mu g/m^3$	ppb	$\mu g/m^3$	ppb
Least health protective end of the risk range	1 case in 10,000 people	$1x10^{-4}$	13.0	4.0	45.0	14.0
Midpoint of risk range	1 case in 100,000 people	$1x10^{-5}$	**1.3***	**0.4***	**4.5****	**1.4****
Most health protective end of the risk range	1 case in 1,000,000 people	$1x10^{-6}$	0.13	0.04	0.45	0.14

*Concentration developed using EPA recommended toxicity, City of Houston number for same risk level

** TCEQ number

The only place where the impact of shale gas exploitation on the atmosphere can be effectively evaluated is the Fort Worth area where shale gas drilling (associated with the Barnett shale) has been going on since the late 1990's. This area was declared an EPA Ozone Nonattainment Area

before gas drilling became a significant issue and is now the site for seven Automated Gas Chromatographs (AutoGCs) which analyze for 45 different VOCs 20 times a day. These units were installed and operated by the Texas Commission on Environmental Quality (TCEQ). The longest record is for a site at Hinton St/Dallas Love Field Airport (twelve years), the second longest is the Ft. Worth Northwest (near Meacham Airfield) which has an eight year record. Eight new AutoGC units have been approved for the Barnett Shale area for a total of fifteen. Some simple annual average benzene values for these TCEQ monitoring sites are shown in Figure X. Two trends are clear from this plot. First there is an overall decrease in benzene values over the last decade, a period of time during which the level of shale gas drilling and gas production from the Barnett increased dramatically. Second, the average level of benzene emissions was higher in the inner urban monitoring stations (Hinton St./ Love Field) compared to more rural sites, that are in the thick of gas activity (such as the new Dish, Texas site).

It is important to understand that the AutoGC units are most appropriate to monitor the cumulative atmospheric impact of effectively non-point sources such as automobile exhausts and widely dispersed point sources such as gasoline stations. Point sources such as batteries of natural gas compressor stations and gas processing plants, cannot be appropriately monitored by a relatively few AutoGC units spread over a large area. It also should be noted that assessment of lifetime exposure levels requires either long term continuous monitoring such as provided by the AutoGC units or extensive, randomly selected, short term sampling on a long term basis. Lifetime exposures cannot be estimated from a small number of short term measurements. Although the contaminant plumes of point sources ultimately contribute to the average compositions of air trapped inside the urban heat island they can only be effectively monitor using targeted technologies that allow greater spatial granularity. Initially to address this issue, and to respond to public concerns, there have been a number of more focused emissions studies sponsored by local government or private foundations.

The first of these more focused studies (and ultimately the most controversial) was commissioned by the small town of Dish Texas to the north west of Fort Worth. Resident complaints of odors and noise from gas well pads and engines. Reports of illness of residents led the Mayor of the town to seek outside help to undertake sampling of air emissions. Wolf Eagle Environmental conducted a set of 24 hour canister samples at four residences in the town

(chosen to be downwind of compressor stations) and reported detection of elevated levels of benzene, xylenes, and naphthalene (WEE, 2009). The results may have surprised TCEQ regulators. Although the Wolf Eagle Environmental study could be criticized for its methodology and overreaching conclusions it did serve a useful purpose in alerting regulators that a detailed program of measurement of emissions was warranted. Similarly a short term emissions study by the environmental group Earthworks in the Dish are reported unexpectedly high levels of carbon disulfide along with dimethyl disulfide and methyl ethyl disulfide. This study also showed methane levels the report described "as much as 20 times above normal background levels" in the air around several counties in the greater Dallas-Fort-Worth Metroplex.

In December of 2009, the TCEQ carried out an intensive three day survey of air emissions (testing for 22 VOCs including Benzene) associated with approximately 126 gas production sites (including well drilling and fracturing operations, disposal sites, and compressor facilities) in the city of Fort Worth. The team was equipped with infrared cameras that can visualize VOC emissions otherwise invisible, hand-held toxic vapor analyzers, and air sampling canisters. This monitoring survey found no pollutants at levels that would be a cause for concern. The TCEQ news release on the study announced that "the majority of the testing during that trip found no detection of volatile organic compounds at all,"

In June 2010 a report on ambient air quality study in the Fort Worth Arlington area was released by Titan Engineering and funded by an industry consortium (the BSEEC).. The study was based on testing for benzene, formaldehyde, and other VOCs. The study found only one facility, a well site in South Fort Worth, with benzene levels exceeding long-term ESLs: the Encana Mercer Ranch. This particular site, consisted of 6 wells producing gas and condensate (so called wet gas), as well as some twenty tanks for condensate and water. Benzene levels from 24 hour readings of 1.96 ppb and a one-hour reading of 3.15 ppb came from within 100 to 150 feet of the tanks. These levels exceeded TCEQ's long-term standard (ESL). As this site has a set-back of 1,000 feet from the nearest protected use BSEEC asserted that the results "showed there are no harmful levels of benzene and other compounds being emitted from natural gas sites tested" (BSEEC, 2010).

One result from these independent studies of atmospheric emissions studies has been an improved understanding of the origin of the VOC's in the atmosphere in areas of intense shale

gas activity. It has become clear that in general most VOC's in the atmosphere in the greater Fort Worth area are not associated with gas production or transport (although this could have been inferred from the spatial variation of the benzene results just discussed). In a study of the Shale Creek area (a very active area of shale gas production, north of Fort Worth and about 13 Km south west of Dish Texas) an independent research group from Nevada's Desert Research Institute found that shale gas was responsible for less than half the VOC's in the atmosphere motor vehicle emissions being the dominant contributor, making up approximately 45% (Zielinska et al., 2010). Natural gas emissions from wells other infrastructure (and from condensate tanks) made approximately 43% of the emissions, with small gasoline engines (such as lawnmowers) making up about 17%. Interestingly analysis of air sampling from sites nearest the local gas processing plant gave similar results to the residential sites. Zielinska et al.'s modeling of individual organic compounds predicted that approximately 70% of isopentane is from engine emissions, while about 70 – 80% of benzene is from "fugitive emissions of natural gas". Xylenes are almost entirely attributed to motor vehicle emissions at most sites.

9 Health Impacts

There is a widespread suspicious among some environmentalists and part of the public health community that shale gas development will have a negative impact on the health in local communities. This is in large part because a number of the contaminations that leak from wells, condensate tanks, engine exhausts and gas processing plants include: known carcinogens (benzene); possible carcinogens (ethylbenzene, acetaldehyde, formaldehyde); and compounds that can cause serious non-cancer health effects (such as toluene, xylene, and benzene). Many of these contaminants can result in a range of neurological symptoms (dizziness and headaches), respiratory problems (throat irritation, and degraded lung function). In the long term these contaminants can result in a range of more serious diseases. Unfortunately many of these contaminants are also associated with vehicle exhausts, gas stations, smoking, dry cleaning operations, and gasoline driven snow blowers, weed wackers, lawnmowers etc.

The residents of DISH, Texas, are often pointed to by opponents of shale gas as a key example of health impacts from atmospheric emissions from wells and compressors (Schmidt, 2011). After complaints by town residents of odors from gas drilling and gas compression plants in and around the town and reports of illness of residents, the Mayor of the town appealed to outside organizations for assistance. In October -November 2009 a survey was conducted of health complaints of 31 volunteers who were residents of Dish at that time. Subra (2009) documented 165 medical and diseases in her survey. The most frequently reported conditions were "sinus problems, throat irritation, allergies, weakness and fatigue, eye irritation, nasal irritation, joint pain, muscle aches and pains, breathing difficulties, vision impairment, severe headaches, sleep disturbances, swollen and painful joints, frequent irritation, skin irritation, wheezing, frequent nausea, ringing in ears, decreased motor skills, loss of sexual drive, bronchitis, easy bruising and difficulty in concentrating". Subra's report had little tangible impact until the discovery of elevated levels of benzene, xylenes, dimethyl disulphide, methyl ethyl disulphide, and naphthalene at four residences in the town by Wolf Eagle Environmental (WEE, 2010) and of elevated levels of carbon disulfide by Subra (2010) resulted in Texas's regulatory agencies conducting more detailed studies of both emissions and blood/urine chemistry of residents.

The Texas Department of State Health Services (DSHS) attempted to sample the blood and urine of 50 residents but they were only able to get 28 blood and urine samples from volunteers. The samples were tests for a wide range of VOCs and HAPs and their metabolites. The results were then compared to national norms from the National Health and Nutrition Examination Survey (NHANES). The Health Services report concluded that the VOC blood levels in the Dish volunteers were broadly similar to the general US population as represented by the NHANES survey (Jia et al., 2008) and that the pattern of blood and urine results is not consistent with a common community-wide exposure to unusual levels of VOCs. The report emphasized that elevated blood benzene levels were associated with smoking with one exception. They also concluded that the levels of VOC metabolites in urine were at levels similar to their control group (DSHS staff) and literature values.

A second study by the DSHS was carried out to respond to concerns in the community that there was cluster of cancer cases in the Flower Mound area near Fort Worth. DSHS studied rates of occurrence of leukemia, non-Hodgkin's lymphoma, childhood brain cancer and female breast cancer in the using decade long Cancer Registry data (from 1998 to 2007). They compared the observed cancer rate with statewide rates and concluded that occurrence of all cancers except breast cancer were "within a statistically normal range" in the Flower Mound area. The DSHS concluded that the increased rate of breast cancer does not have an obvious connection to the observed shale gas related emissions and may in fact be explained by higher mammography use in the area compared to the state average. The DSHS also compared that average annual number of cancer cases in preliminary data for the period 2007 to 2009 with the previous decade and found no statistically significant change in rate though numerically there was a slightly higher rate for leukemia, non-Hodgkin's lymphoma and breast cancer for 2007 to 2009. The DSHS emphasizes that the 2007 to 2009 is preliminary and may well change.

10 Discussion

One gas industry leader has admitted that "development of the Marcellus Shale in the Appalachian Basin is not without controversy" Hull (2010). Further noting that "the speed, at which the Marcellus is being developed" is resulting in "a tension" as to how best to maximize the benefits, "while minimizing the negative impacts on the local environment" Hull (2010).

It is surprising that such a divergence of opinion exists even amongst the scientific community over various aspects of the environmental impact of shale gas extraction. This divergence applies even to aspects where the basic facts are not in dispute. For example the usage of water by the shale gas industry is "staggering" according to (**REFERENCE**). Whereas Arthur (2009) suggests that the "overall" water consumption "is small as well as temporary" when compared to other uses such as for electric power. As noted by Arthur and Coughlin (2011) greatest concern over the impacts of water consumption for shale gas operations have focused on their cumulative impacts. For any shale gas play, the key issue in assessing cumulative impacts, is whether the water consumption related to shale gas activity (over the lifetime of this activity) is going to result in a significant long term loss of water resources within the region. Concern over the cumulative withdrawal of surface water resources is misguided as surface water is renewable. Groundwater resources are only partially renewable (depending on the recharge rate of the particular aquifer), and clearly should be of greatest concern.

An instructive case to make a r ealistic, worst-case, assessment the magnitude of water consumption for producing shale gas is the Eagle Ford shale play. Of all the current significant shale gas production areas in North America today, the Eagle Ford has the highest reliance on largely non-renewable water and has the driest climate. Brownlow (2010) has estimated the total consumption of water over the lifetime of the Eagle Ford play will be 300,000 acre-feet. The present day pumping rate (for this area of the Carrizo aquifer), for all uses other than shale gas, has been estimated as 275,000 acre-feet per year (Brownlow, 2010). If this rate of agricultural and municipal pumpage holds constant over the life of the play (estimated by Nicot and Scanlon, 2012 as on the order of fifty years), then the usage for shale gas will be on the order of 2% of the total. Nicot and Scanlon (2012) have made a detailed projection of water-use for the Eagle Ford play assuming an area for the play of 53,000 km^2, an area significantly larger than that probably

used by Brownlow in his estimates. 1870 Mm^3 (1,520,000 AF) (**Error! Reference source not found.**). Projections suggest that water use will peak in 2024 at 58 Mm^3 (48 kAF) (**Error! Reference source not found.**).

It is more than likely that the total pumpage from the Carrizo aquifer over the lifetime of the shale gas drilling activity will be less than the uncertainty in the recharge rate for the aquifer. The detailed study by LBG-HDR (1998) estimated the potential recharge as Recharge Potential

(acre feet per year) see page 132. Subsequently Scanlon et al. (2000) have reported an order of magnitude range in estimates for recharge rates in the Carrizo-Wilcox aquifer, with recharge values ranging from 0.1 to 5.8 in/yr. It would be reasonable to conclude that, on a regional basis, the water withdrawals for shale gas extraction are insignificant, in that they will not be statistically resolvable by analysis of average water levels. This conclusions says more about our limited knowledge of the recharge rate of aquifers than it does about the magnitude of water demands for hydraulic fracturing. Having made this analysis, it is also clear that water pumping for shale gas related consumption can have significant localized negative impacts. These are most likely to occur in areas of existing high pumpage rates for agriculture or municipal usage where high pumping of wells for shale gas create localized cones of depression that magnify the drawdown of existing wells.

Recently a report by a task force appointed by Texas Railroad Commissioner David Porter has concluded that "data shows Carrizo Wilcox Aquifer contains enough water to support oil and gas development [expected in the Eagle Ford shale play]" (RRC, 2012). The report concludes that "drilling and completions in the Eagle Ford Shale account for approximately six percent of the water demand in South Texas", whereas "irrigation accounts for 64 percent and municipal uses account for 17 percent" (RRC, 2012). Although the details of the report have not yet been made public the conclusion is consistent with the discussion above. However a significant part of the current and future Eagle Ford development will take place above the Coastal Plain Aquifer which has more limited water resources. Closer to the coast during the current drought conditions, operators apparently are seriously considered desalination of sea water as a water source.

In their publication on the impact of the Texas natural gas boom on health and safety, Wilson et al (2011) have asserted, in the context of "increasing scarcity of water supplies", that the "immense quantities" of water used for hydraulic fracturing are "not sustainable". In view of the discussion above it would seem that the majority of the water usage in all shale plays except for the Eagle Ford, is in fact sustainable. It also seems likely that for all the current, major shale plays in North America the non-sustainable portion of the water will not have a significant impact on the long term water resources, at a regional scale. On a local scale, some water conflict issues have arisen in the past with water withdrawals for shale gas drilling playing a possible role in decline in groundwater levels in specific wells. The industry, sometimes with guidance from regulatory agencies, in the past has responded quickly to change water sources.

The location and timing of surface water withdrawals can make a difference by avoiding over abstraction impacts during the dry season in surface water sources that have marginal capacity or are oversubscribed in low flow periods. The cumulative impacts of non-sustainable water withdrawals will limit the exploitation of shale gas resources in semi-arid or arid areas with limited or oversubscribed surface water resources. Abundant groundwater sources Marginal quality groundwater sources (?)

Strategic capture of surface flows during wet season

Ensure adequate pass-by flows

Short and long-range view Active participation in State water planning processes

Use of treatment technologies where practical No magic bullet

Filtration and reuse of produced waters

Continual evaluation of emerging technologies and enhancement

From: Berkowitz M. 2009 Toxic Chemicals on Tap How Natural Gas Drilling Threatens Drinking WaterEnvironment America Research and Policy Center Report November, 2009 From: http://www.circleofblue.org/waternews/wp-content/uploads/2010/08/AME-toxics-report-final-lo-res.pdf

10.1 Environmental Concerns over Hydraulic Fracturing Fluids and Disposal of Flowback Water

The most commonly cited chemicals of concern in flowback water are arsenic, uranium and benzene. Of these chemicals arsenic is the single contaminant that appears to be the greatest concern. Although not uncommon in domestic water wells with no connection to hydraulic fracturing, the detection of arsenic in drinking water in Texas and Pennsylvania has become the cause for outrage amongst home owners and environmental groups. Mall (2011) has reported that the water well of a family in Butler County, Pennsylvania was tested after "nearby drilling and fracking activities in early 2011" showing "high levels of arsenic and other substances". Mall also reports that another well owner in the area, will a well pad as close as 500 feet, became "very ill [when the hydraulic fracturing occurred] for several days--until they stopped drinking [their well water]" with "symptoms that [the well owner believes] can be caused by arsenic poisoning". The PA-DEP tested her water but found no evidence of contamination. Mall (2010) reports that the well owner remains concerned because "her water was not tested for arsenic".

Concern over the presence of carcinogens such as arsenic in flow back water is driving demands for stronger regulation. Even with the introduction of so called "Green" hydraulically fractured fluids the problem of toxic, radioactive, and carcinogenic contaminated flow-back water will largely continue as most of the compounds of concern are extracted out of the host shale. This point has been made by the Sierra Club as early as 2009 when Annie Wilson, Energy Committee Chair of their Atlantic Chapter noted in a formal submission to the New York City Council that "Even if fracking fluid chemicals were not used, substances that normally remain underground are brought to the surface by the fracking process". Wilson (2009) specifically pointed out that "The release of arsenic, heavy metals, radon and other radioactive carcinogens are of sufficient concern in their own right to preclude support of this inherently toxic process". Penningroth (2010), a former Cornell University professor, has asserted that "Flow back is hazardous waste, not industrial wastewater" and has suggested that Congress should "Eliminate exemption of oil and gas industry waste from disposal as hazardous waste under RCRA". Such a development could add considerable cost to shale gas operations. Even if such actions do not occur, management of water with significant arsenic concentrations poses significant reputational risks in the case of tanker truck or pipeline like accidents involving flow-back/produced waters.

The concern of the public and some NGOs over the concentration of Uranium in flowback water has an interesting history. Professor Tracey Bank (UB, 2010; Bank et al. 2010; Bank 2011) created a flurry of news Blog reports initiated by a press release suggesting that dangerous levels of Uranium may be leached out of Marcellus shale during hydraulic fracturing and returned to the surface in flowback water. The University at Buffalo press release (UB, 2010) stated "researchers [Professor Bank and colleagues] have now found that that … hydraulic fracturing -- also causes uranium that is naturally trapped inside Marcellus shale to be released, raising additional environmental concerns". Quoting Bank directly the press release poses a question: "My question was, if they start drilling and pumping millions of gallons of water into these underground rocks, will that force the uranium into the soluble phase and mobilize it? Will uranium then show up in groundwater?" Again in a direct quote Bank answers the question that she posed earlier by stating "the process of drilling to extract the hydrocarbons could start mobilizing the metals as well, forcing them into the soluble phase and causing them to move around." To assess this possibility the press release notes that "When Bank and her colleagues reacted samples in the lab with surrogate drilling fluids, they found that the uranium was indeed, being solubilized". Again in a direct quote Bank suggests that "at these levels, uranium is not a radioactive risk, it is still a toxic, deadly metal". Not surprisingly, Banks press release and articles created a cascade of concern. The Earth Justice Blog (Lawlor, 2010) reported the UB press release as follows "Tracy Bank shows that hydraulic fracture drilling, or fracking, in the Marcellus shale deposit on the East Coast of the United States will result in the pollution of groundwater with uranium. Bank found that naturally occurring uranium trapped in Marcellus shale is released into groundwater following hydraulic fracturing". Similarly a Natural Resources Defense Council (NRCD) Blog featured Bank's question "Will uranium then show up i n groundwater?", and added "The answer, she and colleagues found, is yes". The Bank press release also spawned an article in Science News titled "Uranium in Groundwater? 'Fracking' Mobilizes Uranium in Marcellus Shale" (Science News, 2010). Most significantly perhaps, Bank et al.'s abstract was quoted in a formal letter to the EPA from the NRCD's Amy Mal commenting on the EPA's Draft Hydraulic Fracturing Study Plan to support the assertion that "Flowback and Produced Water … may also contain … naturally occurring radioactive material … [Bank et al., 2010], as a result of contact with subsurface formations and fluids".

Bank (2011a) described three extraction experiments that she performed on Marcellus shale samples, designed to "determine the extent that these metals could be mobilized during reactions that occur between drilling and fracking fluids and the shale". Her first extraction resulted in negligible release of uranium. In the second extraction, finely ground shale was reacted with 3 M and then 1.5 M HCl for a total of two hours. This she reports (Bank, 2011b) released about 25% HCl of the uranium in ground Marcellus shale core. The third and most extreme extraction released more Uranium. These experiments used a 30 percent hydrogen peroxide treatment to "oxidize and remove the organic matter from finely ground shale". A nitric acid treatment was then used "solubilize any metal released by oxidation of the organic matter". This acidification she noted was necessary because "Under neutral pH conditions, oxidized uranium released by the organic carbon removal would sorb to the shale mineral phases". As a result of this rather extreme chemical extraction "up to 35 pe rcent of the uranium was solubilized" in her experiments. Before presenting her talk at the Geological Society of America Bank was interviewed by Green Wire and was quoted as saying "in my opinion, everything that comes out of the holes [Marcellus Shale gas wells], because there's the potential to be enriched with toxic metals, should be considered a toxic waste". To put all this in context, as noted earlier in this paper, the USGS on the basis of their program of chemical analysis of flowback and produced water associated with Appalachian gas deposits has concluded that Marcellus flowback water contains negligible levels of Uranium. The extractions used by Bank (2011a and 2011b) described in UB (2010) as "surrogate frac fluids" were, in fact, much stronger acids and oxidizing fluids than real hydraulic fracturing fluids. The information in Bank et al. (2010), Bank (2011a) and Bank (2011b) does not provide any tangible evidence that supports suggestions that flowback water is contaminated with Uranium nor that it is contaminating groundwater. Unfortunately there is now a widespread, though erroneous belief that Uranium is a common and significant component of flowback water. Lechtenbohmer et al. (2011) for example state that "Through the hydraulic fracturing process, these naturally occurring radioactive materials such as uranium, thorium and radium bound in the rock are transported to the surface with the flow-back fluid".

For the first few years of the Marcellus Gas play companies public water treatment plants in Pennsylvania became the dominant disposal method. Volz (2011) reported that eventually over

50 public water treatment plants in PA were accepting contaminated water from shale gas drilling. As these plants use biological processes they are not designed to treat high salinity fluids rather disposal relied on dilution by larger volumes of municipal waste water. The use of water treatment plants for disposal of saline water has been the source of considerable controversy. Professor Volz from the University of Pittsburgh led a campaign to stop the disposal of saline flowback water. As noted by Zoback et al. (2010), there have been "significant" bulges in levels of total dissolved solids (TDS) in the Monongahela River (PADEP, 2008), an important source of drinking water in Pennsylvania. In 2008 flowback water made up to 20 percent of the water treated by some water treatment plants in Pennsylvania (Zoback et al., 2010). Public concerns resulted in the PADEP initially ordering these plants to limit their acceptance of flowback water (PADEP, 2008) and eventually terminating the practice (**REFERENCE**). Although Zoback et al. (2010) in passing, noted that higher TDS levels are also impacted by drainage from abandoned coal mines, storm-water runoff, and discharges from water treatment plants, they were apparently not aware of conclusive geochemical evidence that coal mine drainage was by far the main cause of the high TDS levels in the Monongahela River in 2008. It has been widely documented that TDS levels of water draining from abandoned and active Appalachian coal mines has been increasing significantly over recent years, as a result of the effectiveness of programs to reduce the acidity of mine drainage (**REFERENCES**). As a result of the neutralization of sulfuric acid in coal mine drainage, these effluents are characteristically high in sulfate ions. In contrast the flowback and produced water from the Marcellus shale play is characteristically low in sulfate. In a study of the TDS issue in the Monongahela River in 2008, Tetratech (2009) concluded that the high TDS levels were in part a result of very low flows in the river due to drought and that "the main chemical component detected in the TDS concentrations… was sulfate, which mostly likely is the result of mine drainage".

When these plants stopped accepting this water from gas producers, recycling of flowback water has become the low cost solution for water management as long as pond storage is available in the vicinity of the drill pads. Rassenfoss (2011) notes that Range Resources began testing recycling of flowback and produced water in their Marcellus operations in August 2009 and 2010 the company reused 96% of its produced water in Pennsylvania. The company is currently

using a mix of fresh water and flowback water passed through a 25 micron filter for hydraulic fracturing in southwest Pennsylvania.

10.2 Water Contamination

In a recent review article in Business Week (sub-titled "Natural gas derived from the process is lifting the economy, but it's environmentally risky") Efstathiou and Chipman (2011) suggest that "reports of contaminated water [wells] and alleged disposal of carcinogens in rivers have caught state and federal regulators, and even environmental watchdogs, off guard". When you trace back the origin of these specific concerns they appear to be related not to chemicals injected in hydraulic fracturing fluids but rather to elements and compounds extracted out of the gas shale during and after the fracturing process. After hydraulic fracturing has been effected and the fluid pressure build up is relieved the water returned from the well (termed flow back) is initially similar in composition the injected fluid. As flowback proceeds over a period of hours it is no longer the fresh water (plus chemicals) injected, but rather becomes increasingly saline representing larger components of saline formation water from the shale. Simon and Fleming (2011) have suggested that although gas production is "a routine practice", that shale gas production necessitates use of hydraulic fracturing "that uses chemicals" and is "far more intrusive to the subsurface environment" than is conventional gas production. This is probably one of the mildest descriptions published in an environmental journal of the potential environmental issues associated with hydraulic fracturing for shale gas extraction.

Complaints by homeowners and some NGO's have resulted in a number of reports by University researchers suggesting that exploitation of shale gas can have serious environmental consequences. Professor Robert Howarth of Cornell University in a letter to the EPA regarding their congressionally mandated study of hydraulic fracturing has expressed an even greater degree of certainty that shale gas extraction has resulted in contamination of water wells. Howarth (2010) suggested that: "It is certain that shale gas development has contaminated groundwater and drinking water wells with methane", adding "the mechanism or mechanisms leading to this contamination remain uncertain". Howarth in an article in Nature poses the question "Have fracking-return fluids contaminated drinking water?" His answer is "Yes, although the evidence is not as strong as for methane contamination" (Howarth, 2011). Howarth does admit that "none of the data has yet appeared in the peer-reviewed literature" but adds that

"a series of articles in The New York Times documents the problem". Perusal of the New York Times articles suggests that the main source of this "documentation" comes via internet bloggers and interviews with individuals who often have a vested interest. In some cases the New York Times articles either ignore the conclusions of official reports by regulatory agencies on these incidents or appear to be unaware of these report. Internet Blogs have become a major source of information (and in many cases disinformation) about the environmental impact of shale gas development. Some papers have multiple paragraphs with facts and factoids taken from Blogs, sometimes referenced as such but often just paraphrased.

Professor Bill Chameides (Dean of the Nicolas School at Duke University) has suggested that "Evidence is mounting that fracking does bad things to people's drinking water". He further suggests that "somehow" hydraulic fracturing is "causing gas and chemicals to migrate upward into well water". Increasingly, people with wells in the vicinity of fracking operations are complaining of drinking water contaminated by natural gas or worse. He further suggests that in some cases "water has become laced with natural gas to the point of posing a safety hazard — like the pipes going kaboom". What Chameides seems to be unaware of is that water wells and associated plumbing in rural PA have been "going kaboom" long before shale gas and hydraulic fracturing came to Pennsylvania. The Pennsylvania Department of Environmental Protection has been warning home owners of the danger of stray methane in water wells and has documented a significant number of stray gas incidents and explosions many of were prior to gas shale drilling. A number of these incidents were related by PaDEP (2009) to gas storage sites or old gas wells that were improperly plugged, and some were unexplained. Few if any appear to have been have been definitively resolved as to their origin.

Very little scientific data or analysis is available on whether drilling and exploitation of shale gas wells is resulting in contamination of aquifers used to supply drinking water. In the abstract to their paper Osborn et al. (2011) conclude that "we document systematic evidence for methane contamination of drinking water associated with shale gas extraction". Five issues raise concern about their study and how the results are being interpreted both by the author's interviews in the press and by others. These issues are : 1) the study appears to have systematic biases in the choice of sampling sites; 2) the unexplained absence of any contamination of the water wells with either components of frac fluid or saline brines from produced water is not explained; 3) the

nature of the proposed leakage is very different from that observed in the documented cases of methane leakage from casing referenced by the authors; 4) there is a fundamental misunderstanding on the part of the authors that identification of thermogenic methane gas in water wells serves as proof that this gas came from shale gas drilling, hydraulic fracturing, and/or shale gas production activities; and 5) the systematic isotopic correlations in their data that are consistent with a common origin for their "active" and most of their "inactive" methane samples.

Only fragmentary evidence is available for how the authors chose their sample sites. In discussing the Osborn et al study, the Associated Press reported (Cappiello, 2011) that "Sherry Vargson's drinking water well in Bradford County had the highest levels of methane detected in the study" and noted that "Chesapeake Energy Corp., has bottled water delivered [to her]." The reader is left to wonder how many of the Osborn et al sample sites were from areas already identified as having high methane water wells by the DEP regulators and/or where water well owners are involved in lawsuits filed against gas companies.

It should be noted that the authors' distinction between active and nonactive sites is entirely arbitrary and a radius of 1 km appears to have been chosen to exclude the results of a large number of water wells with very low methane levels approximately 1.2 to 1.8 km s from extraction (shale gas) wells. There also seem to be a systematic bias in the location of the authors' "nonactive" water well samples. There are no non-active water wells sampled in the same aquifer as the Dimock township water wells. This leaves open the question as to whether there is actually widespread methane contamination in this aquifer independent of the existence of shale gas drilling. Samples taken to the east of Dimock roughly between Brooklyn and Montrose (shown in the inset in Figure 1) are very clustered and do little to characterize the regional background levels of methane. It may be that this clustering was a reflection of the difficulty of obtaining private water well samples. However, it detracts from the authors' argument that high methane levels are not found more than a thousand meters from active shale gas wells.

Several research groups and many environmentalists appear to implicitly or explicitly assume that observations of sudden onset of water well contamination are caused by some form of leakage of fluids from the gas well. For methane contamination, the gas must become dissolved

(to the methane saturation point) in groundwater surrounding the gas well, followed by the flow of this water through the aquifer to surrounding water wells. There are several problems with this hypothesis:

1. In the one documented example (the Bainbridge Ohio incident) where careful detailed study has suggested that domestic water wells were indeed contaminated by methane. This occurred when excessive gas pressure in a newly drilled gas well evidently exploited a flaw in the casing/cement barrier, resulting in a shallow horizontal fracture of the aquifer. This fracturing event squirted methane radially and resulted in methane bubbles travelling through fractures into water wells. As noted above the key difference between the Bainbridge event and methane contamination incidents in Pennsylvania and Texas is that in Bainbridge the concentration of dissolved methane is very low. Similarly in the Crosby 25-3 blowout in Park County, Wyoming, the other well documented example of what happens when there is a blowout of gas through a shallow casing failure, the methane apparently dominated migrated vertically by bubble and slug flow and very little dissolved into ground water.
2. Observed water well contamination, typically high iron, sometimes high manganese as well as iron, and in a number of cases high arsenic, just does not make sense in terms of contamination of fluids from a gas well. None of these elements are characteristic of fracturing fluids, flowback, or produced waters.
3. If the timing of contamination is as described by almost all well owners (immediately as drilling/fracturing took place) then it would be physically impossible for groundwater to flow from the gas well to the water well in that time even for the most transmissive aquifer. Proponents of this idea have a real problem with finding a feasible mechanism.
4. There is a growing body of evidence that methane saturated groundwater is widespread in groundwater aquifers above the Barnett and Marcellus Shales (and probably other gas shales). Examples of seepage of thermogenic methane into higher formations and ultimately into water wells are common in areas of Texas that overlay the Barnett Shale (Kornack and McCaffrey, 2011). Local residents and water-well-drillers in Hood County, Texas have reported that water wells in the area have been historically contaminated with methane (Montes and Chandler, 2011). Years before any shale gas drilling activity, water well drillers have recorded both intermittent and sustained (up to 122MCF per day) natural gas production from some of the water wells drilled in the area (Montes and Chandler, 2011). The isotopic systematics of the methane in the aquifers has been increasingly found to reflect both a thermogenic origin and a commonality in hydrogen and carbon isotope systematics between the shallow gas and the methane being produced from the underlying shale gas. This is to be expected as the shale gas formations are source rocks for hydrocarbons. In some cases where appropriate reservoirs and seals exist, upward migrating gas from the Barnett or Marcellus has become trapped to form gas deposits such as the Bend Conglomerate, the Strawn etc.

So if the well-leak-leading-to-methane-contamination model doesn't work then how can the spatial and temporal correlation between drilling of shale gas wells and water well

contamination, be explained? It could be dismissed as some sort of group hysteria, except that the reports from a large number of well owners have a number of consistencies (and the water analyses have considerable commonalities such has high iron, high turbidity, and in some cases high arsenic values). The following testable hypothesis is capable of explaining the observed observations and the methane gas fizzing and explosions. First we assume that say 10% of the water wells above shale gas formations tap an aquifer saturated in methane. In local areas most of the wells may tap methane saturated water. Second we assume that the interior of the casing of the water well and the bottom of the well is coated with hydrated iron oxide particles, clay, microbial films and what scientists call "sludge". During the drilling and hydraulic fracturing process of the shale gas well, numerous pressure transients and pressure jumps occurs. Each one of these radiates pressure waves that vibrate nearby water wells. As a result, particles from the casing wall and well bottom are agitated into suspension causing the cloudiness, red, orange or gold colors reported by well owners. I have personally experienced our water well in Virginia turning a rust-brown color for days after our well was worked on. High arsenic values can be explained as iron oxides are well known to adsorb arsenic on its grain surfaces and could release arsenic into solution if the iron oxide grains are dislodged from their chemical microenvironment in bacterial encrusted bacterial films on the well casing wall, and dispersed into a different Eh-pH environment could release arsenic adsorbed on iron oxide grains. Finally the same agitation and turbidity described above could nucleate bubbles of methane in gas saturated water. Accumulation of evolved gas in confined spaces could lead to observed explosions. In this model the shale gas drilling and hydraulic fracturing is the instigator of the water contamination issues, acting in a way as a catalyst for contaminants that are already in-place. This model also leads to obvious mitigation actions on the part of both shale gas drilling companies and well owners.

Duncan (2012a) has presented a fact-based view of the environmental impacts impact of shale gas exploitation. Key conclusions include:

- leakage from the actual hydraulic fracturing at depth has not been observed
- Insufficient information currently exists to understand and evaluate the long term, cumulative risks associated with the processes associated with hydraulic fracturing at depth in the long term, after gas production has ceased
- A testable hypothesis has been put forward that explains well owners observations of water well contamination phenomena (coincident with drilling of nearby hydraulically

fractured shale gas wells) without inferring loss of integrity of containment of the well casing of the new gas wells.

- Available evidence suggests that well water quality problems widely ascribed to the drilling of shale gas wells, is more apparent than real. Regional water quality studies in several states, conducted prior to the initiation of shale gas drilling, demonstrate that the kind of contamination ascribed to shale gas drilling is already widespread in local water wells prior to drilling.
- No evidence has been found thus far that environmentally dangerous chemical in hydraulic fracturing fluids are not attenuated to negligible levels by natural processes. Further research is needed to confirm this.

Somehow the rumors and accusation of groundwater pollution in internet Blogs has become translated into "documented examples" across the Atlantic. For example, Broderick et al (2011) assert that "The dismissal of any risk as insignificant is even harder to justify given the documented examples that have occurred in the US, seemingly due to poor construction and/or operator error. These examples have seen high levels of pollutants, such as benzene, iron and manganese, in groundwater, and a number of explosions resulting from accumulation of gas in groundwater". No reference to the "documentation" is given. The fact that iron and manganese are not notable components of hydraulic fracturing fluids or flowback water, or that benzene is not uncommon in rural water wells in Pennsylvania, is not mentioned.

Many, but not all, of the areas being exploited for shale gas in the US have long been the target for oil and gas production (in some cases extending back over a century). Unplugged (or improperly abandoned wells), leakage from old drilling pits, old surface spills (all dating back years, decades and in some cases a century before shale gas exploitation began) have contributed to groundwater contamination in a number of these areas.

Based on studies by the Gas Technology Institute, Edelstein (2011) concluded that the chemical characteristics flowback water are: (1) Low suspended solids and Total Organic Content (TOC); (2) Man-made chemicals "of concern" are at levels below that of detection; (3) Benzene, Toluene, Xylene (BTEX) and poly-aromatic hydrocarbons (PAHs), at "trace levels"; (4) Oils and greases at "non-problem levels"; (5) Soluble organics that are highly biodegradable; and (5) Concentrations of heavy metals that "are lower than in municipal sludge". The risks from long term leakage from deep fractured shale reservoirs would perhaps be downgraded if future detailed studies of flowback water substantiate Edelstein's conclusions.

Ernst and Young (2011) have suggested that "The primary environmental concern" related to the exploitation of shale gas "seems to be the risk of contamination of drinking water supplies by the chemicals used in the hydraulic fracturing process". Perhaps the most detailed recent exposition of the concerns over the chemicals in fracturing fluids has been the congressional report by Waxman et al. (2011). All four chemical compounds raised by Waxman et al. (2011) as being of specific concern are already widely distributed in the natural environment. That is not to suggest that releasing more into groundwater or soils or surface water would be acceptable, but rather than finding any of these chemicals in a way well near a shale gas well is not by itself diagnostic that the well has leaked. Second, the residence time in the subsurface combined with the biodegradation rates of most if not all of these compounds is such that leaking from a hydraulic fracture say thousands of meters hydraulic fracturing fluid (if any) have a high enough initial concentrations to be detectable after dilution, dispersion, adsorption on clay minerals, and microbial degradation, even in deep monitoring wells. The simple water tests typically done regulatory agencies and non-specialized water testing services do not analyze for chemicals that might plausibly be fingerprints for possible fluids leaking from gas wells. It is not clear at the moment what chemical compounds in the long list of components of hydraulic fracturing additives should be monitored for as indicators of possible leakage of such fluids nor which may have potential health impacts. Clearly more research is needed in this area.

10.3 Long Term Risks of Groundwater Contamination from the Deep Hydraulic Fracturing Process

There has been speculation in the journal literature and the press that hydraulic fracturing and/or the high fluid pressures associated with fracturing could either force fracturing fluids up into shallow drinking water aquifers or eventually allow such fluids to flow upwards into freshwater aquifers through existing or newly created fracture pathways. For example Guidotti (2011) has suggested that "The [fracturing] pressures… may drive frack (sic) water and brine-carrying return water up through cracks and faults in the rock, against the gradient of gravity, and may even create new fractures by splitting rock". He further asks "Is there enough pressure to drive it thousands of feet upward to contaminate groundwater or even reach the surface?" Guidotti (2011) then asks "Could the gas itself travel along fracture or fault lines all the way to the groundwater or to the surface?" Curiously Guidotti then asserts that "however unlikely this

seems, some models suggest that it could happen" and that "this seems to be the biggest concern of residents in the area". The author gives no hint as to the reference for the "some models" that suggest "it could happen".

There is a very extensive published literature on the nature and consequences of hydraulic fracturing. The upward propagation of fractures during modern high volume hydraulic fracturing of shale gas reservoirs has been monitoring hundreds of times by high sensitivity micro-seismometers. The fracturing process has been modeled in large computer models to help understand the nature of the fracturing process and hundreds of highly skilled scientists and engineers both in companies and in Universities have studied the results. The following points represent both the broad consensus and conclusions that can be reasonably drawn from this consensus:

1. The magnitude of fluids pumped under pressure during the hydraulic fracturing process is orders of magnitude less than what would be required to propagate fractures upwards to fresh water aquifers through a thousand to four thousand feet or more of layered low- and high-permeability rock (ICF, 2009;
2. That tensile fractures created by hydraulic fracturing will have a very short life of enhanced permeability if they are not propped open by injected sand or other injected proppant particles. Proppants only are dispersed into a fraction of the propagated fracture (Cikes, 2000; Cipolla et al., 2009; Kuochen et al, 2012). At the high temperatures and pressures such unpropped cracks will seal rapidly with propped cracks sealing at a slower rate (Cikes, 2000; Weaver et al. 2009; LaFollette and Carman, 2011).
3. Gas production will create a large zone of lowered pressure in the fractured reservoir that will drive fluid flow in and down, likely for hundreds of years after production has ceased (this is highly worthy of modeling studies)
4. Many of the chemicals in fracing fluids will be rapidly dissipated during the fracturing process by reaction between the fluid and the fractured rock surface (the acid with become rapidly neutralized), and some chemicals will become adsorbed on surfaces of organic components and clay minerals.
5. After the fracturing events are over, any residual, depleted, fracturing fluid would be mixed with dense formational brines (as seen in evolution of the flowback water) which will be essentially impossible to migrate upwards without a very high driving pressure, that doesn't exist. This analysis has been eloquently advanced by Professor Terry Engelder of Penn State University in a series of talks and articles.

Cupas (2009) has suggested that The EPA's draft of EPA (2004) stated that "hydraulic fracturing fluids can move beyond and sometimes significantly beyond, the propped, sand-filled portions of hydraulically induced fractures". Cupas expressed concern that this statement was not in the final

report. Whatever the significance of this specific editorial decision, it is difficult to believe that unpropped tension fractures have more than a brief transitory increased permeability at the pressures and temperatures encountered in fracturing shale gas. Undoubtedly the elastic "snap back" of the unpropped extremes of the induced fracturing network would instantly drive the fracturing fluid back towards the well. As a result there would be no pressure drive for the kind of upward flow of fracture fluid that Myers (2009) speculatively suggests.

A recent article on the regulation of unconventional natural gas development (Mandelbaum, 2011) has noted that some have portrayed the fracturing itself as a risk to groundwater, "focusing on the possibility that hydraulic stimulation will crack confining layers and allow hydrocarbons (or fracturing chemicals) to migrate upward into water-bearing zones". He further notes that "research has not uncovered a report of any such incident" and that "it would require a massive failure of geology and engineering for fracture patterns to travel thousands of feet beyond their intended length, allowing gas to escape into an aquifer". Mandelbaum (2011) concludes that "in the hierarchy of risks, this fear seems to be a distraction".

10.4 Atmospheric Emissions

The NGO Riverkeeper declared that "The Dallas-Fort Worth area has seen a dramatic impact on its air quality from natural gas drilling in the Barnett Shale" (Michaels et al., 2010). This statement has been quoted (amongst others) by Lechtenbohmer et al. (2011) in a European Parliament Report, even though there is an extensive body of evidence reviewed in this paper that does not lend any support to such a statement. Professor Howarth of Cornell University (a vocal opponent of hydraulic fracturing) has recently asserted that "only this year have objective, scientific studies on the consequences [of shale gas exploitation] been published, and these are alarming" (Y-E-360, 2011). Howarth further made the blunt assertion that one of the consequences of the activities of the shale gas industry is that "widespread air pollution with compounds such as the carcinogen benzene is prevalent in both Texas and Pennsylvania" (Y-E-360, 2011). It is well known that aromatic hydrocarbons such as benzene, toluene, ethyl benzene and xylene (BTEX) are typically found in emissions from so-called "wet-gas" wells that produce condensate or oil as well as natural gas. It is also well established in the medical literature that these chemicals are toxic and/or cancer causing for humans. If "air pollution" is defined as air exceeding the EPA's clean air standards is Howarth's assertion that "widespread" benzene

pollution of the atmosphere caused by shale gas activity is "prevalent" in Texas and Pennsylvania justified? Clearly the studies reviewed in this paper are consistent in showing that (except locally in the vicinity of some gas processing plants and compressor installations) benzene pollution derived from shale gas sources is significantly less, than the contribution from automobile traffic and other sources in the urban areas of Fort Worth and Dallas. In more outer suburban and semi-rural areas where benzene from urban traffic is not an issue, benzene levels are a fraction of those in the cities (and lower than what experts regard as dangerous levels), even when these areas are the site of intense shale gas activity (**REFERENCES**).

Production of shale gas clearly contributes ozone precursors (such as VOCs and nitrous oxides) to the atmosphere. So far there has been no comprehensive study of the magnitude of this contribution. In the Dallas Fort Worth area the contribution to ozone from Barnett shale gas activity has been a controversial issue. An analysis of this issue by Armendariz (2009) has asserted that the VOC and NOx emissions from natural gas production in the Barnett shale play a significant role in ozone development. TCEQ (2009) in evaluating Armendariz's report, have criticized the combining of NOx and VOC emissions in his analysis. The TCEQ report noted that modeling of photochemical reactions within the air mass in the DFW nonattainment area has shown that ozone is "much more responsive to NOx [than to VOC levels]". The report also notes that while ozone levels in the DFW area declined in a generally steady way from 2003 to 2008, shale gas activity ramped up steadily during this time period, increasing by a factor of four. It could be argued that in the absence of shale gas activities that ozone levels in the DFW non-attainment area would have decreased at an even higher rate. To evaluate the magnitude of such an impact would require more information of the magnitude and location of point sources (as well as contributions from non-point sources) integrated with modeling of both air dispersion and concurrent photochemical reactions.

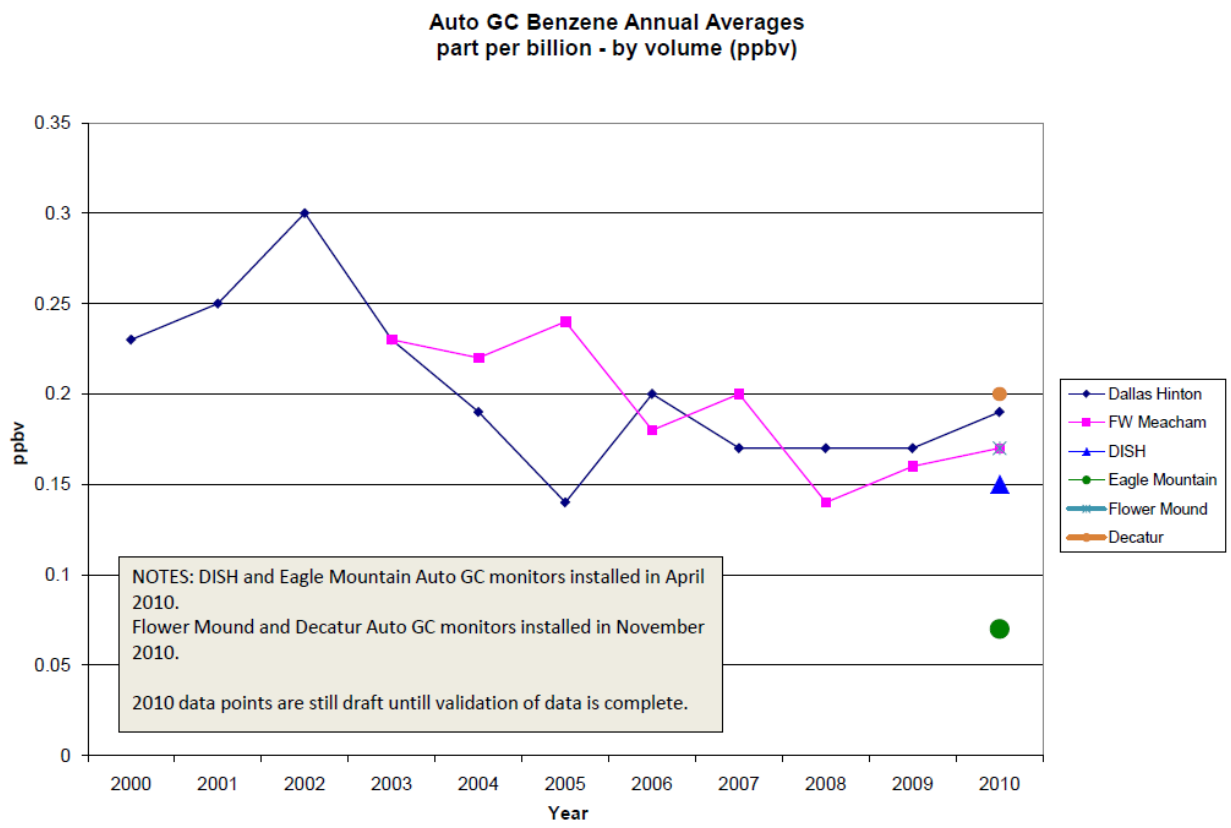
In a provocative article in Nature entitled "Should Fracking stop?" Howarth (2011) states that "Shale-gas development — which uses huge diesel pumps to inject the water — also creates local air pollution, often at dangerous levels". Howarth suggests that "The state of Texas reports benzene concentrations in air in the Barnett shale area that sometimes exceed acute toxicity standards [TCEQ, 2010]". This report, an internal TCEQ Interoffice Memorandum, does not state that benzene values have exceeded "acute toxicity standards". The report presents a large

number of analyses of benzene levels directly associated with condensate tanks, compressors and well heads (on the order of a hundred perhaps) typically inside fenced-off, secure areas. Of these measurements the vast majority were non-detects. Of the sites with measurable benzene the highest values ranged from 1.6 to 95 ppbv with one exceptionally high value of 15,000 ppbv. The obvious question is, do any of these values exceed the "acute toxicity standards". In secure, fenced-off, industrial setting (with typically no on-site employees) the standard for acute toxicity is given by the AEGL standards. These standards consist of AEGL-1 and AEGL-2. These standards in ppbv are AEGL-1(1 Hr) 53,544; AEGL-1(8 Hr) 9,134; AEGL-2(1 Hr) 818,910; and AEGL-2(8 Hr) 201,580 (EPA, 2011). In term of the standards for community exposures the most conservative standards is the California toxicity standard which has an acute level of 409 ppbv and a chronic exposure level of 19 ppbv. So only the single value of 15,000 ppbv is the only one above the California acute standard. Only four of the values from the measurements inside industrial facilities in TCEQ (2011) were above the California chronic standard. All of this suggests that the data in TCEQ (2010) does not support Howarth (2011) assertion that air in the Barnett shale area sometimes exceeds acute toxicity standards.

Howarth (2011) further states that "although the concentrations observed in the Marcellus shale area in Pennsylvania are lower [PaDEP, 2011] … they are high enough to pose a risk of cancer from chronic exposure [referencing Talbot et al., 2011]". Howarth (2011) assertions regarding the Pennsylvanian emissions study are supported neither by the available data, nor by the report and paper he cites. For example the report on emissions from the Marcellus shale Howarth references concludes "PA DEP has determined that benzene should not be considered a pollutant of concern near Pennsylvania Marcellus Shale operations". The same report also states that "the lifetime cancer risk was not calculated for this short-term sampling study". Significantly it goes on to point out that "Typically, a sampling period of at least one year is necessary for a lifetime cancer risk analysis". In addition the paper by Talbot et al. (2011), quoted by Howarth (2011) to support his assertion that the benzene levels measured by PADEP (2011) are "high enough to pose a risk of cancer from chronic exposure"), does not address the levels of chronic atmospheric benzene exposure that would result in a measurable increase in cancer. The PADEP studies were short term measurements at industrial installations that cannot be meaningfully used to asses chronic community exposure. As such the appropriate metrics are OSHA standards for benzene

exposure related to cancer hazard: TWA 1,000 ppb; STEL 5,000 ppb; and an action level of 500 ppb (Weisel, 2010).

In urban drilling environments such as Fort Worth Texas the atmospheric emissions from shale gas drilling may well be significantly less than the contributions from other sources. ERG (2011) has compiled estimated VOC's from Tarrant County to be 4,800 tons a year from oil and gas production (most all shale gas) compared to 10,600 tons from road vehicles, 2,300 tons from gasoline stations, and 810 tons from dry cleaning, bulk gasoline terminals and residential natural gas. These estimates come from model emissions rather than direct measurements and they may actually overestimate the contribution from gas operations in Tarrant County. The estimates do show that very significant amounts of VOC emissions come from sources other than gas activity. This is supported by long term measurements of VOCs and other air pollutants by continuous monitoring of the DFW non-attainment area.



DISCUSS THE ABOVE DIAGRAM

To put the benzene values found in shale gas areas into a national context, Clements et al. (2006) reported that the maximum 24-hour average concentrations of benzene reported for four U.S. cities in 2004: were 3.5 µg/m3 for St. Louis, Missouri; 8.6 µg/m3 for Chicago, Illinois; 9.3 µg/m3 for Los Angeles, California; and 234.8 µg/m3 for Houston, Texas. In addition as the EPA has long noted, high indoor benzene levels in houses with smokers is by far the highest level of human exposure to benzene we encounter in normal living. None of this should suggest that VOC's levels from shale gas activity are inconsequential or not requiring more careful and extensive monitoring.

There are concerns being expressed by residents in areas impacted by shale-gas activity that the spatial and temporal concentration of drilling rigs and associated diesel compressors, diesel generators, heavy truck traffic and vented/flared emissions that tend to be associated with shale gas exploitation create short lived problems for air quality particularly in terms of VOC, nitrogen oxides, ozone and particulate levels. This kind of localized relatively short term air hazard is off particular concern when babies and young children are exposed. For example Madsen et al. (2011) have noted that over 320 day care facilities, 67 schools and 9 hospitals are located within two miles of permitted well sites and that a significant fraction of these are closer than one mile. Our knowledge of the transient impacts to VOC levels close to arrays of active drilling pads appears too limited. Typically the only information available comes from short-term outdoor grab samples that do not necessarily represent 24-hour or annual exposure levels.

Arguably the kind of ongoing systematic air monitoring being done by government agencies is inadequate to identify the apparently small percentage of compressor, condensate tank and related shale gas operations that appear to emit the majority of VOC's. Realistically only the operating companies have the ability to monitor such problems with their own operations. To achieve this goal, states should create regulatory incentives that encourage companies to improve their attention to issues like broken valves and flares that have lost their flame.

In some of the western states (Colorado and Wyoming), oil and gas air emissions are the largest regional source for VOCs and related high ozone levels. In rural Sublette County, Wyoming, an area with intense natural gas drilling winter ozone levels routinely spike exceeding the EPA's 8-hour ozone standard of 75 ppb, making the air quality sometimes worse than that in Los Angeles (WDEQ, 2010; WDEQ, 2011; Schmidt, 2011). Keith Guille (quoted in Schmidt, 2011) with the

Wyoming Department of Environmental Quality, notes that "[The oil and gas industry is] certainly our biggest sources of VOCs and NO_X," however, Guille also observes that ozone is created when VOCs and NO_X interact with sunlight, particularly when reflected by the Counties continuous winter snow cover. S now cover and a common temperature inversion in the atmosphere above the county both play a key role in the ozone build up. The Sublette County case illustrates that oil and gas industry emissions can impact regional air quality and that other natural factors can play a key role. So it is well established that oil and gas activity can created significant air pollution problems. However in some large part these problems are controlled by specific regional circumstances of atmospheric inversion layers and factors controlling photochemical reactions. The emissions levels that create an atmospheric pollution problem in one part of the country may have little impact elsewhere.

10.5 Health Issues

Professor Conrad Volz has written about how water, land management, ecological, and diverse contaminant sources interact to produce tertiary public health, medical, social, and economic problems. He noted that chemicals that impact health including VOCs "such as benzene, toluene, and xylene", as well as dangerous compounds "derived from gasoline, non-latex paints and varnishes, cleaning solutions, and dry cleaning" (Volz, 2007). Separating the impact on health of one factor such as air emissions of benzene from one source such as gas shale production from the impact of smoking, work place exposures and so on, is a complex task.

As portrayed documentary films such as "Gasland" shale gas extraction and processing is often accompanied by anecdotal reports of health issues such as headaches, diarrhea, nosebleeds, dizziness, blackouts, and muscle spasms (Schmidt, 2011). A number of chemicals associated with hydraulic fracturing have the potential to cause a range of serious health problems (see Colborn et al., 2011; Steingraber, 2011). Although it is probable that exposure to fracturing chemicals has occurred (such as to workers on shale gas drilling rigs and those involved in surface spills of fracturing chemicals for example) linkages between source and receptor have not been scientifically established and there has been little systematically collected epidemiological evidence that connect natural gas production to health problems. The assertions of Colborn et al. (2011) and Steingraber (2011) focus on t he intrinsic properties and health effects of chemical compounds associated with natural gas extraction (that is the potential

hazard), rather than on realistic, documented exposure scenarios (that is the risk). What must be identified is not only a hazard (the dangerous chemical) but also an exposure pathway that results in the substance being injected by humans at levels that are of concern. An exposure pathway links the source of contamination to a mechanism for transporting it (such as flow of groundwater) to a point of exposure (a domestic water well for example), as well as a receptor (such as a family drinking the water). If the hazardous chemical is adsorbed onto clay surfaces and/or consumed by microbial action in the groundwater aquifer, the exposure pathway is not completed and the risk is avoided. For example Colburn et al. (2011) use the underground blowout of the Crosby well in Wyoming as an example of the risk of endocrine disruptors and carcinogens used in drilling fluids. What Colburn et al. (2011) fail to discuss is the fact that after this blowout and extensive groundwater monitoring program was carried out with the drilling of monitoring wells, together will sampling and analysis for specific chemicals in the drilling mud. Not only were none of these chemicals found in domestic water wells surrounding the site, none were found in the monitoring wells specifically drilled to detect possible contamination (REFERENCE).

Unfortunately several chemicals associated with either flowback water or atmospheric emissions from gas wells and gas infrastructure have the potential for significant negative impact on human health (given exposure, particularly to vulnerable populations such as embryos, babies and young children). For example recent research suggests that benzene impacts blood at low levels exposure with no evidence of a threshold, thus "there is probably no safe level of exposure to benzene, and all exposures constitute some risk" (Smith, 2010). As will be seen in the discussion below large cohort epidemiological studies of the effects of benzene exposure do not substantiate the low level exposure concerns of Smith (2010), however no such studies appear to have been done on babies or children. Weisel (2010) has recently noted that understanding the toxicity of benzene will require evaluation of the differences in metabolic rates between human and animal doses, as well as the presence of polymorphisms to properly evaluating the risks from environmental exposures.

An additional concern is a set of chemicals termed endocrine disruptors; man-made chemicals if absorbed into the body mimic or block hormones thus disrupting the normal functions of chemical-signaling in the body potentially impacting growth, reproduction, and metabolism

(Colborn, 1995; Krimsky, 2001). Similarly to benzene, it is not clear that there is a level of endocrine disrupting chemicals that does not impact health. Some researchers suggest that concentrations on the order of parts per trillion can cause gene alteration resulting in birth defects or cancer (Vanndenburg et al., 2009; Beronius et al., 2010). The field of endocrine disruption is highly and with skeptical protagonists being as strident as the supporters.

Some epidemiologists have questioned whether any impact of endocrine disruptors can be discerned in health and mortality statistics (Safe, 2000; WHO, 2002), though this seems to be a minority viewpoint. There are many plausible hypothesizes in this area of research however developing robust approaches to testing them is difficult (Krimsky, 2001). Similarly translating small animal studies to complex epidemiologic settings is difficult. Beronius et al. (2010) have reviewed risk assessments for a specific endocrine disruptor that has ranged from "there is no risk to any part of the population" to "there is risk to the entire population". Behind this wide range in assessments Beronius et al. (2010) found that there are "prominent differences" in how various assessments of risk of endocrine disruptors interpreted the" reliability, relevance and overall significance of toxicity data". Vanndenburg et al. (2009) reviewing the controversies surrounding endocrine disruption have concluded that "The data collected thus far in the field of environmental toxicology are sufficiently robust to raise concerns about the potentially deleterious impact of endocrine-disrupting chemicals on human development". Whether or not this will prove to be a consensus opinion is not clear however in assessing risks associated with shale gas it is probably best at this time for the purpose of risk mitigation, to be conservative and assume that any proposed endocrine disruptor can have a potential impact at concentrations of parts per trillion.

Our society faces a real problem in that benzene (and other VOCs), PAHs, HAPs, and a variety of endocrine disruptors are widespread pollutants in our environment independently of any contamination from shale gas production. To place the statements in the previous paragraph in an appropriate context it should be noted that individual loadings of benzene and other BTEX compounds is dominated (for most of the population) exposure to tobacco smoke (either direct or indirect), highway driving, time spent in gas stations, time spent in urban environments and so on. At the same time many of us probably have a range of endocrine disruptors in various old bottles of household cleaners, tile floor treatments and window cleaners under our kitchen sinks.

This does not justify any industrial contamination of the air or water, but it does complicate the interpretation of epidemiological studies.

Perhaps the only controlled human epidemiological study that has suggested a correlation between employment in the oil and gas industry and disease was conducted by Mills, et al. (1984). This study suggested this association, based on 347 m edical records of patients with testicular cancer. However this study does not appear to be widely supported by other experts in the field. First Becker (1984) has critiqued the Mills et al (1984) study because it was based on "a clearly biased hospital sample", used "questionable methods for verifying employment", used a control group 79% of which had other malignant tumors and failed to "match patients and controls for area of residence". Further both Garner et al.'s (2005) and Mester et al. (2010) have written comprehensive reviews of the epidemiology of testicular cancer, and although both reference the Mills at al. (1984) study in the context of risk to agricultural investments, neither included oil and gas workers in their discussion of occupations possibly related to increased probability of cancer.

No mortality studies appear to have been conducted on w orkers in the up-stream gas industry. Only one such study (with a cohort of over 19,000 men) has been completed on oi l industry workers exposed to crude oil (Devine and Barron 1987; Divine and Hartman, 2000). This study concluded that mortality was not increased significantly for all cancers, stroke, heart disease and respiratory disease and that overall mortality and overall cancer incidence among these workers are significantly lower than in the general population. In a study of exposure of workers to oil based drilling fluids on of fshore North Sea platforms Eide et al. (1990) concluded that insufficient information was available long-term impact on "carcinogenicity and changes in the lungs". Steinsvåg et al. (2007) have examined the exposure to carcinogens (including benzene, formaldehyde, trichloroethylene, dichloromethane). In this and several similar studies (Gardner, 2003; Bratveit et al., 2007) no c orrelation between exposure and cancer rates has been established. Rather these studies are preparatory to a large-cohort epidemiological study.

In terms of the impacts of exposure from oil and gas activities on nearby inhabitants, large cohort studies with coupled exposure evaluations appear to be lacking. A cohort study of refinery workers carried out by McCraw et al (1985) identified an excess of acute myeloid leukaemia. However this study was based on eight cases all of whom had jobs not identified as having high

benzene exposures. Another study of workers in a refinery by Tsai et al. (1983) failed to find deaths from leukaemia (with 0.4 expected). The median benzene exposure in the study was 140 ppb, and of 1,394 personal samples taken over ten years, only 16%, contained more than 1,000 ppb.

A large cohort study of cancer mortality among 4,417 chemical plant workers exposed to benzene was conducted by Collins et al. (2003). This study concluded there was "little evidence of increasing risk with increasing cumulative exposure for all leukaemias or acute non-lymphocytic leukaemias (ANL), or the other lymphohaematopoeitic cancers with the exception of multiple myeloma". In addition the study found that peak exposures over 100,000 ppb of benzene for 40 or more days was correlated with a greater than expected number of all leukaemias, ANL, and multiple myeloma. Collins et al. (2003) noted that the number of deaths in their study was small, that "the number of peak exposures greater than 100 ppm to benzene" is a superior predictor of risk compared to the cumulative exposure.

Barregard et al. (2009) have studied the incidence of Leukemia in people living close to and down-wind of an oil refinery emitting VOCs including benzene. The study utilized VOC emission data, dispersion modeling, and monitoring measurements, to estimate contribution the refinery to the population's exposure to benzene and other VOCs. They found that the incidence of leukemia in the downwind area' was significantly increased between 1975–2004; with 33 cases versus 22 expected cases over that period with 19 observed cases versus 8.5 expected 1995 to 2004. At the same time the leukemia incidence in the control area (up-wind) met expectations with 50 observed versus 56 expected cases. Based on monitoring and dispersion modeling the refineries contribution to the populations mean-annual, VOC loading was approximately 2 mg/m3 for benzene, 2 mg/m3 for ethylene, 0.5 mg/m3 for 1,3-butadiene and 5 mg/ m3 for propene (Barregard et al., 2009). The authors, using estimates of risk "extrapolated from high-level exposure", concluded that an increase of leukemia rate at such low VOC exposures would not be expected.

In discussing their results Barregard et al. (2009) express some degree of skepticism asserting that their r findings "may reflect a causal association due to emissions, but it could also be due to unknown confounding, or chance". This in part may because a number of similar studies in the United Kingdom (three separate studies) and in Italy have found no significant increase in

Leukemia in close proximity to refineries. The same Swedish research group has studied the population living near a petrochemical complex in Sweden where the ambient air is contaminated with a range of carcinogens such as ethylene, benzene, and 1,3-butadiene (Axelsson et al., 2010). The result of their study was that living close to petrochemical industries was not found to increases the risk of cancer. Similarly Tsai et al. (2004), in a study in of a population in Louisiana within a concentration of several refineries and petrochemical plants, concluded that mortality from cancer was statistically indistinguishable from that elsewhere in the state.

Although most large cohort studies of exposure in the downstream oil and petrochemical industries have failed to demonstrate a strong correlation between exposures to benzene and other VOCs and either cancer or mortality rates there are other types of evidence of health impact being found. One is evidence of chromosome damage. Studied the impact of low level exposure to benzene (related to working in the petrochemical and petroleum refining industries), on the frequencies of chromosome aberrations. The study, based on analysis of blood samples from 178 exposed workers compared with 36 unexposed workers, concluded that the frequency of chromatid deletions and aberrations in those exposed to benzene were higher by a factor of nearly two, than those not exposed. This difference was statically significant even after adjusting for age, smoking status, and alcohol intake. Unfortunately the exposure levels (especially the peak exposures) are not known for the participants in this study. However if they are similar to the worker exposures recorded in the refinery worker studies reviewed above, then these results may refer to benzene levels an order of magnitude of more than exposures to the general public in areas of intensive shale gas extraction.

No large scale or comprehensive studies have been made of health or mortality outcomes related to gas production or processing. Epidemiological studies of the general population, that may have relevance, do not demonstrate a definitive association with natural gas production. For example, based on data from the state of Texas, Lupo et al. (2011) have concluded that mothers from areas with “the highest benzene levels” were “more likely to have offspring with spina bifida” than women in areas with “the lowest levels [of benzene in the atmosphere]”. To the extent that exposure of pregnant women, babies and young children to high environmental levels of benzene, formaldehyde, other VOC’s, PAH’s, HAP’s and fine particulates can be tied to gas

extraction, a variety of medical risks become worrisome (Duong et al., 2011; Lupo et al., 2011; Pandya et al., 2002; Sacks et al., 2011; Perera, et al. 2009; and Slama et al., 2009). Not surprisingly wildlife embryos are impacted in a similar manner to human embryos (Hamlin and Guillette, 2011).

The short term study of VOC levels in a sample of the population of DISH Texas has been the only health related study that has focused specifically on the possible impact of shale gas extraction. The response to the DSHS study from the anti-hydraulic fracturing protagonists was predictably strong. As recounted by Josh Fox in his treatise Gasland Reaffirmed (Fox, 2011)… "Wilma Subra, MacArthur Foundation Genius Award-winning chemist analyzed the new data at a recent public meeting: 'According to DSHS, 50 percent of the people in DISH have levels of chemicals associated with compressor station and pipeline emissions over the general population of the United States in their blood, urine and tap water. Half the population is a huge percentage for people being exposed to the chemicals that are being released in DISH.'" The TDSHS study references the individual data to the median values for national survey and of course one would expect 50% of a sufficiently large sample to be above the median. A second controversy centered on the benzene results, again from Fox (2011) quoting Subra "They found benzene in six people, and DSHS are saying that those people are smokers. Five of those *were* smokers". This issue refers to the fact that out of twenty eight people tested, six residents of Dish in the DSHS study had detectable benzene levels in their blood. Of these six, four had benzene blood levels above the 95 percentile in the national survey. All four were smokers and their blood levels were consistent with the range expected in smokers. The one non-smoker with detectable benzene, had levels an order of magnitude below the 95 percentile from the national survey.

Apparently based on the in DSHS study (but not referencing it), Rahm (2011) suggested that "blood and urine samples taken from residents living near [Dish, Texas] Barnett Shale gas wells" revealed that "65% of households tested had toluene in their systems and another 53% had detectable levels of xylene" and that "these chemicals have all been identified in Dish air samples on multiple occasions". These statements are not found in the DSHS (2010) but can be calculated from the data in the report (see the blog by Tillman, 2010). The DSHS (2010) report presents an analysis that shows that the Dish blood levels have a median lower than (but statistically indistinguishable from) the general U.S. reference population. Of the eighteen

residents with detectable Toluene levels, five have levels above the 95 percentile of the national reference population. Of these four were smokers and one was identified as having probable occupational exposure. In the case of m-p/ Xylene, of the fifteen residents with detectable blood levels, four had levels greater than the 95 percentile. Of these four two were smokers, one had probable occupational exposure and one had possible occupational exposure. The DSHS report concluded that "the pattern of VOC values [in blood samples from Dish residents] was not consistent with a community-wide exposure to airborne contaminants, such as those that might be associated with natural gas drilling operations" (DSHS, 2010). It would be difficult to make a cogent argument that this conclusion is not justified by the data presented. The inference of the reporting of the results of the DSHS study in Rahm (2011) is that it found community-wide, BTEX contamination caused by shale gas operations.

Finkel and Law (2011) have suggested that "little research" has been completed on "the potential adverse health effects of fracking". This is true, but it is also true the gas industry has been using hydraulic fracturing for over 50 years that the epidemiologic studies examined in this review have not revealed any direct evidence for health impacts on workers in this industry nor the public living near oil and gas industry activity. What is largely unprecedented is the development of urban drilling for gas in major cities such a Dallas and Fort Worth, Texas. Review of the atmospheric emissions studies in the DFW area suggests that significant VOC emissions are associated with a minority of gas related installations such as certain compressors and condensate tanks. Before any health studies are undertaken it would seem to be a higher priority to focus on identifying any exposures from emissions. Perhaps the best way to lower health risks related to shale gas is to encourage adoption of best practices in construction and operation of such facilities. Best practices might include using electrical compression engines in area of high population density for example.

10.6 Are Regulatory Frameworks in Place that Minimize Risk of Environmental Damages?

Early in 2011, Steven Chu (US Sec. of Energy) formed a Shale Gas Subcommittee (SGS) of The Department of Energy's Science Advisory Board (SEAB) to make recommendations to promote the safety and environmental performance of shale gas extraction. The first report on hydraulic fracturing asserted that "strong regulations and robust enforcement resources and practices are a

prerequisite to protecting health, safety and the environment" (SGS-SEAB, 2011). They also noted that the lowering these impacts was "easier" when companies are "motivated and committed to adopting best engineering and environmental practice". Key concerns identified by the SGS included: (1) possible air pollution and water contamination associated with shale gas extraction; (2) possible pollution of drinking water by methane and hydraulic fracturing chemicals; and (3) community disruptions including increased truck traffic.

Whether existing regulations in place for well construction are sufficient to avoid future problems (and whether existing regulations are being adequately enforced), has been an issue of considerable controversy, the details of which are beyond the scope of this paper. Well integrity problems resulting in leakage can be divided into two categories sometimes called annular flow and leak flow. In annular flow, fluids move broadly up the well, travelling up the interface between the rock formation and cement, or between the cement and the casing or between the casing and plug material. The flow is though imperfections, channels, fractures or through porous flow. Leak flow is defined as flow in a radial direction out of the well into the formation. Leak flow can take advantage of the some of the same imperfections listed above; however leak flow is most likely related to cracking, corrosion, or some other form of breaching of the casing/cement sheath.

There is little publicly available information that would enable an informed assessment of how many shale gas wells now have or are likely in the future to have significant well integrity issues. Industry well integrity experts have noted that a significant percentage of offshore oil and gas wells (45% in the Gulf of Mexico, 34% in the UK portion of the North Sea, and 18% in the Norwegian portion of the North Sea) have some degree of well integrity issues such as high gas pressures in the annulus (Feather, 2011). The data quoted by Feather does not translate directly into leakage but it does show that industry in the recent past has had endemic well integrity issues while at the same time the significant differences from region to region must reflect differences in factors such as differing requirements or regulatory enforcement.

The gas industry and service companies are actively developing improved cement types to effectively seal well casing and prevent leakage of produced water and/or gas into freshwater aquifers. Schlumberger (2011) has suggested that cement sheath damage or "debonding" can allow "nuisance gas" to migrate to the surface and that there are "thousands of wells" that are

impacted by this phenomena. The company is promoting a self-healing cement technology that they suggest can solve this problem. Numerous other examples of such technologies supplied by other companies could be documented but the key point is that industry has developed technologies to improve well bore integrity and potentially greatly decrease the likelihood of long term leakage. Are there testing programs to establish which of these approaches is most appropriate? Industry, through the American Petroleum Institute (API), has a long tradition of creating "best practice" handbooks based committees of experts with a wide range of technical expertise. These hand books are the focus of extensive technical reviews to incorporate the best of evolving technology and practices. There are three API guidelines specific to the issues covered in this paper: (1) HF1 – Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines, 1st Edition, October 2009; (2) HF2 – Water Management Associated with Hydraulic Fracturing, 1st Edition, June 2010; and (3) HF3 – Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing, 1st Edition, February 2011. It should be noted that in some large part these documents came from a com pilation of earlier API guidance documents on a myriad of smaller recommended practice and guidance documents on specific sub-topics compiled in these three reports. If gas drilling by companies does not follow API best practices the companies may later find itself at a disadvantage in defending any possible law suits related to the well.

In addition to these established best practices there are significant research and technology transfer programs underway to develop strategies for extracting shale gas that have less environmental impact. One such project is the Environmental Friendly Drilling program at HARC in Houston Texas. This group has developed a scorecard to help guide low impact drilling for shale gas in environmentally sensitive areas taking into account "air, site, water, waste management, biodiversity and societal issues" (Haut et al., 2010). Their approach aims reduce the "environmental footprint of operations" by encouraging new approaches to (1) transporting materials to and from the well pad, (2) reducing the well-pad area, (3) adopting alternative power management for drilling, and (4) using improved waste management practices at the well pad (Haut et al., 2010).

A recent report (GWPC, 2009), from the Groundwater Protection Council, entitled "State Oil and Gas Regulations Designed to Protect Water Resources", attempts to assess the effectiveness of

the regulatory frameworks currently used by state government oil and gas regulatory agencies in protecting fresh water aquifers. This report was based on an assessment each state's regulation of drilling, construction, completion and plugging of wells; as well as the construction and operation of above-ground storage tanks, impoundments. In the context of their ability to protect groundwater the GWPC report concluded that state regulations are "generally adequate". The report made two main recommendations: that best practices should be developed for effective hydraulic fracturing practices (adjusted to fit the needs of individual states; and that the capabilities and operation of the national, non-profit organization State Review of Oil and Natural Gas Environmental Regulations (STRONGER), should be expanded (to elements not covered by the current state review guidelines) and strengthened. STRONGER does peer-review of regulatory activities of state agencies upon request. These reviews are conducted by a panel of volunteers from other state agencies, the oil-and-gas industry, and environmental organizations. STRONGER can play a critical role in helping states develop effective regulatory frameworks and to foster the adoption of best practices such as those put forward by the API. The report also concluded that implementation of electronic databases for regulatory information has been a significant addition to state agency capacity. Although some form of data bases on spills related to gas production are maintained by a number of states (Colorado, Pennsylvania and West Virginia) these data are lacking in metrics for the consequences of the spills and are not user friendly in terms of analysis of statistical trends. Further development of data management systems such that currently scattered environmentally related data are gathered together and made readily available will greatly increase transparency. The GWPC is also working to expand a risk-based, data-management to facilitate the exchange of information between states on hydraulic fracturing operations.

A more recent report sponsored by the GWPC (Kell, 2011), reviews regulatory agency records in Texas and Ohio to determine the causes of groundwater contamination incidents related to oil and gas industry exploration and production activities. The study evaluates how the experiences and insights from decades of regulatory investigations have shaped the regulatory frameworks of these two states and ultimately resulted in process improvement of standard industry practices. Kell notes that state agencies "prioritize regulatory reforms" and strategically adjust rules that reduce risk of future contamination. Kell's study looked at a 25 year period (1983-2007) in Ohio

where he examined 185 groundwater contamination incidents related to oil and gas activities. One hundred and forty four of these incidents of groundwater contamination were related to regulated industry activities, the rest from leakage of orphaned wells. Just over half of the regulated incidents occurred from 1983 to 1987 in the first five year increment of the study period. Since 1983 the number of groundwater contamination incidents declined significantly (approximately 90% by the last study increment, 2002-2007. In Texas during the 16 years from 1993 to 2008, over 16,000 horizontal shale gas wells, with multi-staged hydraulic fracturing stimulations (over 13,000 in the Barnett Shale) were completed. During this period, the Rail Road Commission investigated 211 incidents of groundwater contamination and significantly, not a single water contamination incident has been identified associated with these hydraulic fracturing operations (Kell, 2011). Neither state has documented any contamination of groundwater caused by site preparation or fracturing stimulation of tight gas sands nor shale gas wells.

One problem with state agencies regulatory approaches to surface impact is that they are typically based on enforcing a set of rules or Best Management Practices (BMPs) rather than monitoring the impacts of the practices on the local environment. Citations for violations involving land impacts typically record a failure to maintain a correct filter fence; rather than say, exceeding some level of suspended sediment in the local stream. Short of developing a new performance or outcome based regulatory framework (REFERENCE DUNCAN SUBMITTED), enforcement of well-thought-out BMP's can be an effective way to help minimize surface impacts. In this context it is unfortunate that some companies appear to have developed a track record of failure to comply with such regulations. Examination of the PA DEP reports on regulatory enforcement shows that some companies have developed an unfortunate track record for compliance failure in this area. One company for example in Pennsylvania in 2009 aggregated multiple violations for failure to implement BMP's for surface erosion and related surface spill problems at 13 different well sites. This resulted in a number of citations and fines of nearly $100,000. For companies with annual revenues on the order of a billion dollars such fine may not be a deterrent but the reputational risk of such citations may act as a larger deterrent.

It is encouraging that a number of shale gas companies are implementing practices that exceed regulatory requirements. For example in the Barnett Shale play, Devon has implemented "green completions" using technologies that capture gas that would be normally be vented and/or flared during completion of wells. The use of these technologies greatly lowers not only methane emissions but also eliminates VOC emissions. In the Marcellus Shale play in Pennsylvania, EOG is storing all fracturing fluids, flowback and produced water in lined enclosed tanks. The company is also installing protective liners on the well pad under the storage tanks and the area where trucks deliver the fluids.

Subra (2010) has suggested that to protect ground water resources, a "regulatory mechanism" should be implemented "to identify and evaluate the locations of orphan and abandoned well sites in the area of the proposed wells and in the areas to be fractured". Subra's concern is that hydraulic fracture could intersect such wells.

Subra W., 2010, C omments on Hydraulic Fracturing to the Louisiana Senate Environmental Quality Committee http://leanweb.org/our-work/water/produced-waters/comments-on-hydraulic-fracturing-to-the-louisiana-senate-environmental-quality-committee

Ubinger et al. (2010) have suggested that the "complexity and potential impacts" from hydraulic fracturing of Marcellus Shale wells warrants a "pre-permit" application process that involves a "more in-depth analysis of site specific conditions" than that required by current regulations in Pennsylvania. The drivers behind their suggestion is consistent with the conclusions from this current paper that natural gas migration either from natural pathways or from old and/or improperly abandoned oil or gas wells can pose a threat to human safety that can and should be identified and mitigated prior to shale gas drilling. As Ubinger et al. (2010) note, there are believed to be on the order of 184,000 old, undocumented, oil and gas wells in Pennsylvania. A best practice that would help both shale gas companies and the local community is a practice whereby water-wells within a few thousand feet of any shale gas well would be sampled and chemically analyzed for methane and a battery of other possible pollutants both before and after drilling and hydraulic fracturing operation is completed.

(Riha and Rahm, 2010) Impacts from uncertain events (spills and leaks, contaminant migration) can be minimized by targeted regulations, encouragement of preventative best management practices, and establishment of accurate and timely reporting guidelines.

Develop transparent monitoring and reporting systems that assure the public that shale gas drilling is occurring in a manner that protects our water resources.

Although the discussion above has emphasized improving the effectiveness of regulatory frameworks, other approaches may be effective in reducing the environmental impacts of shale gas operations. For example contracts for leasing mineral rights often carry penalties for waste, and emissions from leaks are wasteful. Similarly insurance companies may begin to insist that companies follow best practices to obtain insurance. In the final analysis gas companies would be well served to put more emphasis on training staff to have a higher level of safety vigilance in terms of recognizing and correcting on-site issues that can have an environmental impact. Companies also would reduce their risk of environmental impact by insisting that both on-site and offsite (trucking companies for example) contractors used only properly trained and licensed workers and equipment that meets all state and federal safety requirements.

Irrespective of the nature of the regulatory framework all stakeholders would benefit from greater transparency on the part of industry. Just one example is the issue of emissions from impoundments. Volz et al. (2010) have suggested that the concentration of VOC's in impoundments holding flowback water have the potential to create "serious" air pollution issues. Some residents in the vicinity of such impoundments have complained (Legere, 2010) of "odors like that of gasoline and kerosene". No chemical analyses of flowback water (or measurements of emissions from impoundments) could be found during this review to support the assertions of Volz et al. (2010). Anti-shale-gas-activists point to photos of impoundments next to well pads engulfed what can best be described as a fireball with huge billowing black smoke (REFERENCE). It may well be that this specific fire was related to a surface spill of diesel from an on-site storage tank, but the impression is left with the general public that flowback water is a cesspool of flammable organic chemicals. Ironically the shale gas industry would be better served if individual companies (and regulators) had not only a greater degree of transparency in dealing with accidents but also took a pro-active stance in making information on environmental impacts readily available to the public. In almost all cases it is likely that the reality of any

accident is significantly less than what the imagination of information-starved local residents will create in the absence of facts.

11 Conclusions

The current state of distrust between gas companies and water well owners that exists in some areas of north Texas and in Pennsylvanian towns such as Dimock has created an acrimonious public dialogue of charge and counter charge that ultimately is detrimental the local communities, the industry, and the environment. Only through an open and informed dialogue between industry, regulators, the local communities and other stakeholders can we make forward progress. Increased transparencies on the part of the natural gas industry, together with fostering an improved understanding of technical issues on the part of the local community are important first steps.

Amy Mall, Senior Policy Analyst Natural Resources Defense Council has suggested in recent congressional testimony addressing hydraulic fracturing has suggested that "Not only is there limited scientific knowledge about the impacts of oil and natural gas production, but current regulations, as well as enforcement capabilities, are insufficient".

Dr Cal Cooper "Society benefits from high-quality research that advances knowledge and ultimately makes us more comfortable with the difficult choices we face".

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5 Regulation of Shale Gas Development

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1 Introduction

As gas and oil development from shales has expanded in the United States, various entities have expressed concerns about potential environmental contamination, health effects, nuisances, and impacts on local roads, among other possible effects. The public has tended to direct its focus toward one stage of the shale development process called slickwater "hydraulic fracturing," wherein an operator, after drilling a well, typically injects large quantities of water combined with relatively small quantities of chemicals[1] down the well bore to fracture the shale around it or to expand existing fractures, thus exposing more surface area within the stratum and enabling gas or oil production. This paper provides a brief overview of federal regulation of oil and gas development and fracturing and describes how local, state, and regional statutes, regulations, and policies (referred to broadly as "regulation" or "regulations") address the potential effects of hydraulic fracturing as well as other stages of shale gas development. In the course of describing these regulations, the paper suggests how regulation could better respond to science-based[2]

[1] The chemicals are estimated to make up less than one percent of the solution pumped down the well to fracture it, as measured by weight. *See* Joseph H. Frantz, Jr., *Natural Gas, Range Resources, and the Marcellus Shale*, 2010 No. 5 Rocky Mtn. Mineral Law Foundation-Institute Paper No. 2, at 3 (Dec. 6-7, 2010) (estimating that chemicals represent "0.1% of the mix"); New York State Dep't of Environmental Conservation, Preliminary Revised Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Program (Sept. 2011), *available at* http://www.dec.ny.gov/data/dmn/rdsgeisfull0911.pdf (from sample fracturing fluid compositions in the Fayetteville and Marcellus Shales, estimating that "approximately 84 and 90 percent of the fracturing fluid is water; between approximately 8 and 15 % is proppant; the remainder, typically less than 1 % consists of chemical additives").

[2] From the legal perspective, weighty associations attach to the term "science-based." As Professors Wendy Wagner and Tom McGarity of the University of Texas School of Law observe, industry actors sometimes object to regulation by claiming that it is not based in "sound science," but many actors—from industry or other fields—also may attempt to influence science to achieve "economic or ideological ends." THOMAS MCGARITY AND WENDY WAGNER, BENDING SCIENCE: HOW SPECIAL INTERESTS CORRUPT PUBLIC HEALTH RESEARCH 1 (Harvard Univ. Press 2008). In a world of competing interests and objectives, it is sometimes difficult to identify what, exactly, "sound science" or "science-based" means, and to separate this word usage from various political implications. This paper attempts to avoid using the term "science-based" in a manner that suggests economic or ideological ends. It presumes that the terms "science-based" or "fact-based" refer to conclusions rooted in observation and analysis of effects and predicted effects—recognizing that regulation is never purely "scientific" because regulators work with imperfect data, respond to competing policy objectives, and often must attempt to control the risk of rapidly-changing technologies, the effects of which are still not fully known. As Wendy Wagner also has noted, there is, overall, a dearth of adequate data in environmental regulation, and this

concerns about shale gas development. The paper compares regulations in sixteen select states that have recorded shale gas, shale oil, and/or tight gas production as of 2009 or likely soon will produce these resources.

makes the regulatory task all the more difficult. *See* Wendy Wagner, *Using Competition-Based Regulation to Bridge the Toxics Data Gap*, 83 IND. L.J. 629 (2008). This often forces regulators to guess about effects.

2 Scope of Coverage; Objectives and Methods

This paper addresses the regulatory component of "Fact-Based Regulation for Environmental Protection in Shale Gas Resource Development," a project led by the Energy Institute at the University of Texas, by describing and analyzing state statutes, regulations, and policies that applied to shale gas development—or had been proposed—as of August 2011.[3] This provides the source material from which to assess whether the laws respond to facts—enabling a better understanding of how, and to what extent, regulations incorporate the science of shale gas development and address the potential environmental effects of the practice.

States wrote most of the regulations described in this report prior to the rise of slickwater hydraulic fracturing—the typical method of extracting natural gas from shale.[4] State oil and gas agencies, whose primary responsibilities include conserving oil and gas, protecting "correlative" rights (ensuring against illegal drainage, example), and, more recently, implementing environmental protections,[5] have long administered regulations that require, for example, adequate casing (lining) of wells to protect groundwater and minimum construction requirements for surface pits that store oil and gas waste. Most these regulations, which are addressed in this report in detail, are not specifically tailored toward fracturing or shale gas development more generally—in part due to their age. Rather, as worded, they *can* be read to apply to at least one stage of shale gas development due to their general language but were not written with this development in mind. Recent tailored, regulations, such as Pennsylvania's limits on total

[3] In limited circumstances, the paper addresses state regulations and policies that have been enacted and/or proposed since August 2011.

[4] *See* Railroad Comm'n of Tex., Water Use in the Barnett Shale, Jan. 24, 2011 (explaining that "[]in 1997, the first slick water frac (or light sand frac) was performed and found to be very successful in stimulating the Barnett Shale).

[5] *See* Ground Water Protection Council, State Oil and Natural Gas Regulations Designed to Protect Water Resources 13-15 (May 2009), *available at* http://www.gwpc.org/e-library/documents/general/State%20Oil%20and%20Gas%20Regulations%20Designed%20to%20Protect%20Water%20Resources.pdf; Mike Soraghan, Mike Soraghan, *Protecting Oil From Water – The History of State Regulation*, E&E News, http://www.eenews.net/public/Greenwire/2011/12/14/1.

dissolved solids in the wastewater from hydraulically fractured wells[6] (since partially mooted by advice that operators should not send waste to POTWs);[7] several states' updated requirements for well casing and blowout prevention;[8] New York's proposed mandate for the use of steel tanks for fracturing wastewater ("flowback") storage and greenhouse gas emissions from drilling and fracturing, among many other protections;[9] Fort Worth, Texas's requirements for the and a number of states' chemical disclosure requirements,[10] help to demonstrate some of the new concerns posed by the rise of slickwater fracturing and other stages of shale gas development. The effectiveness of these regulations and their advisability of course remains disputed. The use of steel tanks to store wastewater, for example, may reflect environmental concerns associated with leaking storage pits but may be costly for operators.[11] A requirement that operators conduct testing of water wells near oil and gas sites prior to drilling and fracturing, in turn, may be opposed by landowners who would view testing as a trespass or a water quality monitoring device as a t aking of their property. Discussion of both existing regulations and the few regulations that have been revised to address fracturing—even if these regulations have imperfections—allows other team members at the Energy Institute to more closely analyze whether recent state regulatory responses to shale gas development are grounded in science.

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[6] 25 PA. CODE. § 95.10(b) (West 2011).

[7] *See* Dan Hopey & Sean D. Hamill, *Marcellus Wastewater Shouldn't Go to Treatment Plants*, PITTSBURGH POST-GAZETTE, Apr. 19, 2011, *available at* http://www.post-gazette.com/pg/11109/1140412-100-0.stm (describing a request sent by the Pennsylvania Department of Environmental Protection to gas operators),

[8] *See, e.g.*, Arkansas Oil and Gas Comm'n Rule B-19, http://www.aogc.state.ar.us/PDF/B-19%20Final%201-15-11.pdf; Mont. Admin. Code § 36.22.1106 (2011) (unofficial final rules); N.D. Admin. Code § 43-02-03-21; 43-02-03-27.1 (proposed rule changes 2012), *available at* https://www.dmr.nd.gov/oilgas/rules2012changes.pdf; Proposed Rulemaking, Environmental Quality Board, 40 Pa.B. 3845, July 10, 2010, http://www.pabulletin.com/secure/data/vol40/40-28/1248.html; regulations codified at 25 Pa. Code § 78.83 et seq. (2011).

[9] *See generally* New York State Dep't of Environmental Conservation, Preliminary Revised Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Program, *available at* http://www.dec.ny.gov/data/dmn/rdsgeisfull0911.pdf.

[10] *See infra* table 7a. Arkansas, Colorado, Louisiana, Montana, New Mexico, New York, North Dakota, Texas, and Wyoming have some of the most detailed disclosure requirements (or proposed requirements).

[11] *Cf. infra* note 319 for sources describing oil and gas producers' opposition to New Mexico's "pit rule," which requires the use of steel tanks in certain quantities.

To provide the regulatory foundation for the broader "Fact-Based Regulation" project led by the Energy Institute, this paper describes and analyzes state regulations of shale gas and/or oil development in select states where this development is proceeding or soon will commence. Specifically, it identifies the most relevant statutes, regulations, and policies (broadly described throughout the paper as "regulations" or "regulation") that apply to each stage of the shale development process and compares the content of these laws by state. The report then builds from the scientific and media-based analyses prepared by Professors Duncan and Eastin to provide a preliminary analysis of whether and how these laws respond to the science of shale development.

To define the scope of the regulatory data to be collected, the authors, consulting with other team members, first identified states that have or may soon have shale gas or oil development or similar development, including drilling and fracturing in tight sands. According to the Energy Information Administration, in 2009, twelve U.S. states produced shale gas, including Arkansas, Colorado, Kentucky, Louisiana, Michigan, Montana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, and West Virginia.[12] Shale gas development in Montana, New Mexico, and North Dakota has not been common; Montana and North Dakota primarily produce shale oil,[13] and New Mexico primarily produces gas from tight sands formations. Other states with potential shale gas production include, *inter alia*, Illinois and Indiana (New Albany);[14] Maryland and Ohio (Marcellus and Utica Shale);[15] New York (Marcellus and Utica);[16] Utah (Uinta);[17] Virginia (Big

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[12] U.S. Energy Information Admin., Shale Gas Production (2011), http://www.eia.gov/ dnav/ ng/ng_prod_shalegas_s1_a.htm.

[13] See U.S. Energy Information Admin., Technology-Based Oil and Natural Gas Plays: Shale Shock! Could There Be Billions in the Bakken?, (Nov. 2006) (describing "booming" Bakken Shale production).

[14] *See* U.S. Energy Information Admin. (2011), Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays 15-16 http://www.eia.gov/analysis/studies/usshalegas/pdf/usshaleplays.pdf (describing the potential of the New Albany shale play of Illinois, Indiana, and Kentucky, estimated to have 10.95 trillion cubic feet of technically recoverable reserves, for which nine companies held leases in 2008).

[15] *See id*. at 5 (describing how 1.09 and 18.19 percent of the areal extent of the Marcellus is in Maryland and Ohio, respectively, and how the Marcellus in total is estimated to have 177.9 trillion cubic feet of technically recoverable reserves, for which nineteen companies held leases in 2008. Other estimates for total Marcellus reserves are much higher. *See, e.g.*, Terry Engelder and Gary G. Lash, *Marcellus Shale Play's Vast Resource Potential Creating Stir*

Sandy);[18] and Wyoming (Mancos and Hilliard-Baxter-Mancos).[19] This paper does not explore all states with potential shale gas or oil production. Indeed, certain states with high production potential, such as Mississippi,[20] are omitted due only to time and space limitations. The paper addresses regulations in select states (a sample of sixteen), which already have produced, or soon may produce, gas or oil from shales or tight sands. This sample includes Arkansas, Colorado, Kentucky, Louisiana, Maryland, Michigan, Montana, New Mexico, New York, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, West Virginia, and Wyoming.[21] The sample is not comprehensive, and oil and gas development practices vary among formations[22] and by the type of resource being extracted. Lessons from one state therefore may not be fully transferable to others—due not only to differences in practices but also to climate, geography, and other differences. Technologies for developing shales and tight sands are similar, however, and lessons from each type of formation and resource are relevant to the other. The sample of sixteen states

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in Appalachia, AM. OIL & GAS REP. (May 2009), *available at* http://www.geosc.psu.edu/~engelder/references/link150.pdf (estimating "a total resource of the Marcellus play of nearly 50 Tcf"—an estimate that has since risen).

[16] *See id*. at 5-6 (describing how 20.06 percent of the areal extent of the Marcellus underlies New York).

[17] *See id*. at 68 (describing the USGS of the Uinta Piceance Basin in Colorado and Utah, estimated to have between 1.8 and 4.9 trillion cubic feet of technically recoverable gas) (citing

USGS. *Assessment of Undiscovered Oil and Gas Resources of the Uinta-Piceance Province of Colorado and Utah.* 2002).

[18] EIA, *supra* note 14, at 9-10 (describing the potential of the Devonian Big Sandy shale gas play, estimated to have 7.4 trillion cubic feet of technically recoverable reserves, for which ten companies held leases in 2008).

[19] *See* EIA, Review of Emerging Resources, *supra* note 14, at 63-64 (describing the Hilliard-Baxter-Mancos shale play in Wyoming and Colorado, estimated to have 3.77 trillion cubic feet of technically recoverable reserves, for which five companies hold leases); *id.* at 67-68 (describing the Mancos play in Colorado and Wyoming, estimated to have 21.02 trillion cubic feet of technically recoverable reserves, for which nine companies hold leases).

[20] The Tuscaloosa Marine Shale underlying Louisiana and Mississippi

[21] Ohio and Maryland, which overlie portions of the Marcellus Shale, may soon produce shale gas. Wyoming has not yet experienced shale gas production but has experienced tight sands production. See e-mail from Tom Doll to Jeremy Schepers, June 21, 2011 ("Wyoming has not had activity in shale gas exploration. We have had activity, starting in late 2009 to-date in 2011, in the Niobrara shale oil formation as well as oil exploration in tight oil sands of the Sussex, Parkman, Turner and Frontier formations, all occurring [sic] in 5 counties in the eastern half of Wyoming.").

[22] *See, e.g.*, Halliburton, U.S. Shale Gas, *available at* http://www.halliburton.com/public/solutions/contents/shale/related_docs/H063771.pdf (describing drilling and hydraulic fracturing techniques in shales around the United States and how they differ).

described here provides examples of regulatory approaches to shale gas development, highlights the differences among some state regulations, and offers potential lessons for other states engaged in or soon to explore shale gas production. Although this paper refers to regulations that apply to "shale wells" or "shale gas development," these regulations also apply to shale oil and tight sands wells. With the exception of spacing requirements for wells, special coalbed methane restrictions, and special requirements for the casing (lining) of wells in certain deep formations and formations in which the operator does not know what pressures to anticipate, states often do not differentiate among formations in oil and gas regulation.

Having identified states that currently or soon will have oil or gas development from shales or tight sands, the authors next defined the relevant stages of the shale gas development process to which regulations apply, including development stages that are not unique to shale wells. This enabled a comprehensive review of the regulatory process for shale wells. Generally speaking—ignoring, for the purposes of this introductory stage, key details and variations among wells—an operator developing a s hale well first obtains data, often collected through a process called seismic testing,[23] to estimate the location and abundance of gas underground. The operator selects a drilling location based on these data and a number of other factors, including accessible topography and the availability of mineral rights to lease, for example.[24] After obtaining the necessary mineral rights and regulatory approval of the well location, as well as other permits,[25] the operator constructs a well pad and access road at this location, and drills a well. Operators

[23] *Cf.* Owen L. Anderson and Dr. John D. Piggot, *3D Seismic Technology: Its Uses, Limits & Legal Ramifications*, 42 ROCKY MTN. MINERAL LAW FOUNDATION-INSTITUTE 16 at 4 (1996) (explaining that "geophysicists who use 3D seismic technologies, together with geologists and engineers, are necessary components of the petroleum team," that the use of 3D seismic technology "promises to become the exclusive seismic tool for future field development," and that seismic technology use is becoming "more routine").

[24] *See, e.g.*, Frantz, *supra* note 1, at 3 (explaining that energy companies acquire leases and that "geophysicists determine drilling locations" using "surface, subsurface maps," 3-D seismic measurements, and "state-of-the-art technology").

[25] States require the operator to obtain a permit to drill prior to commencing well construction. *See, e.g.*, 16 Tex. Admin. Code 3.5 (2011) (providing that "[a]n application for a permit to drill, deepen, plug back, or reenter any oil well, gas well, or geothermal resource well shall be made"). As discussed throughout the paper, states also may require the submission of disposal plans and environmental reviews.

increasingly drill horizontal wells for shale development,[26] in which the drill bit cuts down vertically through the formation but is then gradually deviated to a ninety-degree angle.[27] Horizontal drilling and fracturing introduces locational flexibilities, which, depending on states' spacing regulations, allow multiple wells to be drilled on one pad and also allow operators to avoid sensitive surface locations, such as valuable wildlife habitat.[28] During drilling and fracturing, any gas that escapes is captured, vented, or flared (burned off),[29] and following the completion of drilling, casing, and fracturing the well, the first gas produced is similarly captured or flared (burned off).[30] As part of the drilling process, an operator cements of casing (typically steel pipe[31]) into the well.[32] As the well is being drilled, the operator often installs and cements

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[26] *See, e.g.*, Penn. Dep't of Envtl. Protection, Hydraulic Fracturing Overview, *available at* http://www.dep.state.pa.us/dep/deputate/minres/oilgas/new_forms/marcellus/Reports/DEP%20Fracing%20overview.pdf (explaining that "[c]urrent drilling practices in the Marcellus Shale in Pennsylvania utilize both horizontal and the more traditional 'vertical' wells,'" and that both vertical and horizontal wells in the shale typically require hydraulic fracturing); Railroad Comm'n of Tex., *supra* note 4 (describing the quantities water required for slickwater fracturing of vertical and horizontal wells in the Barnett Shale). *But see* Penn. Dep't of Envtl. Protection, Drilling For Natural Gas in the Marcellus Shale Formation, Frequently Asked Questions, http://www.dep.state.pa.us/dep/deputate/minres/oilgas/new_forms/marcellus/MarcellusFAQ.pdf "Extracting natural gas from the Marcellus Shale formation requires horizontal drilling and a process known as 'hydraulic fracturing' that uses far greater amounts of water than traditional natural gas exploration."). This above statement is incorrect, as some wells in the Marcellus are only vertically (not horizontally) drilled and are fractured. *See* J. Daniel Arthur et al., Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale, *available at* http://www.dec.ny.gov/docs/materials_minerals_pdf/GWPCMarcellus.pdf.

[27] *See* Frantz, *supra* note 24, at 4; U.S. DEP'T OF ENERGY, ENVIRONMENTAL BENEFITS OF ADVANCED OIL AND GAS EXPLORATION AND PRODUCTION TECHNOLOGY 36 (1999) (describing
How horizontal wells "deviate from the strictly vertical orientation by anywhere from a few degrees to completely horizontal, or even inverted toward the surface").

[28] Horizontal drilling can substantially reduce surface disturbance *See, e.g.*, Frantz, *supra* note 24, at 5 (noting that horizontal wells "[g]realty reduce surface impact" and "[m]inimize disturbance"); U.S. DEP'T OF ENERGY, *supra* note 22, at 36 (noting that "production footprints" in Alaska have "shrunk dramatically" as a result of horizontal and other innovative drilling and also have minimized disturbance of sensitive habitats); *id*. at 37 (listing the environmental benefits of horizontal drilling as including "fewer wells," "lower waste volumes," and "protection of sensitive environments"). It also may concentrate certain environmental effects, such as air pollution, within one area.

[29] New York Preliminary Revised SGEIS at 5-134.

[30] *Id*.

[31] Ground Water Protection Council, State Oil and Natural Gas Regulations Designed to Protect Water Resources 18 (May 2009), *available at* http://www.gwpc.org/e-library/documents/general/State%20Oil%20and%20Gas%20Regulations%20Designed%20to%20Protect%20Water%20Resources.pdf ("Casing is typically steel pipe used to line the inside of the drilled hole (wellbore).").

[32] For a detailed description of the casing and cementing process, *see id*. at 19-20.

into the wellbore several types of casing—each of an incrementally small diameter.[33] This casing includes conductor casing to prevent the top of the well from collapsing in on itself,[34] surface casing that runs from the surface down to a certain depth to protect fresh water and other substances around the well,[35] intermediate casing to support well structure of other natural resources farther from the surface,[36] and deep production casing to allow the gas or oil produced to flow up through the well.[37] These drilling techniques will differ substantially depending on the composition of the formation, the depth at which a well is drilled, and other factors, and should be understood only as a general description.[38]

During drilling, fluid called "produced water" comes up naturally out of the formation; the operator temporarily stores this water on site, along with drill cuttings (rocks and other substances that come up out of the drilled formation) and other drilling waste such as used drilling muds[39] and fluids, and then disposes of it. The wastes are either stored in closed steel tanks (in what is called a "closed loop system") or in surface pits. Depending on state regulations, the pits may be unlined or lined with clay, a synthetic material, or other substances depending on state regulations, and their contents must be disposed of within a certain amount of time after the drilling and fracturing operation has ended.

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[33] *See id*. at 19 (explaining that "the casing of oil and gas wells, whether vertical and horizontal, is accomplished in multiple phases from the largest diameter casing to the smallest").

[34] *See id*. (explaining that conductor casing is installed to "prevent the sides of the hole from caving into the wellbore where it is drilled through unconsolidated materials such as the soil layers").

[35] *See id*.

[36] *See id*. (explaining that intermediate casing is "usually only required for specific reasons such as additional control of fluid flow and pressure effects, or for the protection of other resources such as minable coals or gas storage zones").

[37] *See* FracFocus.org, Well Construction & Groundwater Protection, http://fracfocus.org/hydraulic-fracturing-how-it-works/casing; New York Dept. of Envtl. Conservation (2011), New York Supplemental Generic Environmental Impact Statement preliminary revised draft 5.9, http://eidmarcellus.org/wp-content/uploads/2011/07/SGEIS-Preliminary-Revised-Draft-7-1-11.pdf.

[38] *Cf.*, New York Preliminary Revised SGEIS at 5-30 (noting differences in drilling techniques and the "iterative process" of hydraulic fracturing design).

[39] Drilling muds often contain chromium and barium. *See* Joseph Dancy, *Solid Waste Management and Environmental Regulation of Commonly Encountered Oil Field Wastes*, 35 A ROCKY MTN. MINERAL LAW FOUNDATION SPECIAL INSTITUTE at 3 (Feb. 1994).

Disposal techniques for drill cuttings, drilling fluids, produced water, and other drilling wastes vary. Both the drill cuttings and the produced water may contain low levels of naturally-occurring radioactive materials or "NORM" wastes.[40] Some states allow the cuttings to be mixed with soil on site or spread on the surface of the well site through a process called landfarming or land application,[41] or require that the cuttings be transported to an approved disposal facility; state regulations for storage and disposal of drilling fluids sometimes differ depending on whether the fluids are petroleum, salt, or water-based.[42]

Produced water, which may have high levels of chlorides and other total dissolved solids ("salty" substances[43]) in addition to NORM, may be landfarmed or land applied after the operator conducts required soil tests, applied to roads (through a disposal method called "roadspreading"), sent to a centralized disposal facility, sent to a wastewater treatment plant, or disposed of in an underground injection control (UIC) "Class II" disposal well under the Safe Drinking Water Act. The SDWA regulates the construction of UIC wells to prevent contamination of underground sources of drinking water, and it classifies these wells based on the materials in the wells, such as hazardous wastee or oil and gas waste.[44] Centralized surface disposal facilities for oil and gas wastes, which are state regulated, often are called "E&P" facilities.[45] E&P refers to

[40] New York Preliminary Revised SGEIS at 6-205.

[41] *See, e.g.*, CODE. MD. REG. § 26.19.01.10 W; CODE. MD. REG. § 26.19.01.06 F(2)(g) (West 2011) (providing for landfarming or offsite disposal); Oklahoma Admin. Code § 165: 10-7-19 (2011) (allowing land farming of cuttings in certain soils); 25 PA. CODE § 78.61 (a), (b) (allowing land application at the site).

[42] *See, e.g.*, New York Preliminary Revised SGEIS at 7-65 (proposing to require that cuttings from oil-based drillings be disposed of in an approved solid waste facility).

[43] *See, e.g.*, Dancy, *supra* note 39, at 13 (in 1994, indicating that "produced water in the mid-continent area has a total dissolved solids ("TDS") content of approximately 50,000 parts per million (PPM) on average" and that "the average TDS level of produced water (50,000 ppm) exceeds the solids content of seawater (approx.. 34,500 ppm)").

[44] *See* U.S. Envtl. Protection Agency, Classes of Wells, http://water.epa.gov/type/groundwater/uic/wells.cfm.

[45] *See, e.g.*, Oklahoma Admin. Code 165:10-9 (providing requirements for commercial pits).

"exploration and production" oil and gas wastes, which are exempt from federal hazardous waste disposal requirements.[46]

Following the drilling and casing of a well, the operator punches holes in or "perforates" small, below-ground portions of the well and casing within the shale layers to be fractured. To perforate the well, the operator lowers a type of "gun," typically powered by an electric charge, far down the well. (The perforating "gun" is a large, sturdy metal pipe with multiple holes punched in it; bullet-type objects fly out of these holes when the gun is lowered far into the well and set off.) The operator uses this gun to perforate the small portions of the well and casing at which fracturing will occur and gas will be produced; for one stage of fracturing, for example, the operator may perforate a four-foot segment of the wellbore at a depth of 8,000 feet (or another depth that the well log suggests has the most gas) —both to allow gas to flow and to allow acids and fracturing fluids injected down the well to enter the shale around the well.[47] Selection of the perforation and fracturing depth depends on a number of factors, including the nature of the reservoir produced.

After perforating a portion of the well, the operator then prepares for the slickwater fracturing operation. To fracture a well, the operator withdraws water from an underground or surface source or uses recycled, treated wastewater from another well, pipes in or trucks this water to the site (or drills a well on site),[48] and mixes the water with chemicals. The operator typically uses

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[46] For a summary of the E&P wastes that are exempt from federal hazardous waste regulation, *see* State Rev. of Oil and Natural Gas Environmental Regulations, Inc., Guidelines for the Review of State Oil & Natural Gas Environmental Regulatory Programs § 2.6, June 2000, *available at* http://www.dep.state.pa.us/dep/deputate/minres/oilgas/STRONGER.pdf (including, for example, produced water, drilling fluids, drill cuttings, "well completion, treatment, and stimulation fluids" (this category covers fracturing fluids), and pits sludges "from storage or disposal of exempt wastes").

[47] *See* U.S. Dep't. of Energy, *supra* note 27, at 36 (explaining that an operator "perforates the well casing at the depth of the producing formation to allow flow of fluids from the formation into the wellbore"); New York Dept. of Envtl. Conservation, *supra* note 37, at § 5.9.

[48] *See* New York Dept. of Envtl. Conservation, *supra* note 37, at p.8 (estimating that "2.4 million to 7.8 million gallons of water may be used for a multi-stage hydraulic fracturing procedure in a typical 4,000-foot lateral wellbore."); R.R. Comm'n of Texas, *supra* note 4 ("Slick water fracing of a vertical well completion can use over 1.2 million gallons (28,000 barrels) of water, while the fracturing of a horizontal well completion can use over 3.5

approximately ten or eleven chemicals selected from a potential list of more than 250 chemicals;[49] the handful of chemicals chosen from this long menu vary substantially depending on formation characteristics. These chemicals perform functions such as reducing the friction in the well (which is caused by pumping millions of gallons of water down the well at high pressure), carrying "proppant" in the fracturing fluid to prop open fractures in the shale, releasing the proppant once it reaches the shale, and killing bacteria in the shale that might interfere with the fracturing process.[50] Before injecting the water-chemical mixture called fracture or "frac" fluid into the well, the operator cleans the shale around the well by injecting an acid into the well.[51] He or she then injects the fracturing fluid into the well at high pressure along with a proppant, such as sand, to prop open fractures in the shale once they are formed. This allows gas to flow through the fractures in the shale and up t hrough the well. Flowback water—the fracturing fluid that flows back up out of the well after a fracture treatment—is stored temporarily in pits or tanks on site and then disposed of either through recycling, land application, a wastewater treatment plant, or an underground injection control well. Following drilling and fracturing, the operator attaches equipment to the wellhead to control the flow of gas, retains some pipes on site to transport the gas to a processing plant, and removes other equipment from the site. Finally, the operator revegetates the site; the level of site remediation varies depending on the regulations of the state in which the well is located.

After identifying these relevant stages of well development, the authors located state, and regional regulations that potentially apply to each stage (and, in limited circumstances, local regulations). The authors focused most closely on state regulations because states have core regulatory responsibility for oil and gas development. To identify the regulations, the authors

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million gallons (over 83,000 barrels) of water."); *infra* notes 219-220 (providing more sources and estimates of water use). Water use varies substantially depending on the length of the horizontal (lateral) bore and whether dry gas or wet gas is produced. Wet gas requires processing (which uses additional water), while dry gas typically does not.

[49] New York Dept. of Envtl. Conservation, *supra* note 37, at § 5.9.

[50] *Id*.

[51] *Id*.

reviewed the existing literature; searched oil and gas and environmental statutes, regulations, and Westlaw and LexisNexis databases; spoke with attorneys; and searched state agency web pages for regulations, requirements within drilling and other permits, and recent agency directives. The authors then identified the core content of each relevant regulation or agency requirement. Examples of these regulations are summarized and analyzed below. The paper also briefly explores alternatives to regulation, such as best management practices, but does not describe in-depth the range of extra-regulatory controls, such as internal industry guidance and requirements for review of environmental impacts, which can further control effects.[52]

[52] *Cf.* Ground Water Protection Council, *supra* note 31, at 6 ("To gain a more complete understanding of how regulatory programs actually function, one has to evaluate the use of state guides, manuals, environmental policy processes, environmental impact statements, requirements established by permit and many other practices.").

3 Overview of Federal Shale Gas Development Regulation

Entities at the local, state, regional, and federal levels all regulate aspects of the shale gas development process. Locally, municipalities—depending on the state in which they are located—zone oil and gas development (within the powers grand to them by states), tax oil and gas operators, regulate road use, and control certain aspects of the oil and gas production, such as insurance and bonding, fencing of well sites and pits, prevention of water contamination, chemical disclosure, and the timing of oil and gas drilling.[53] The extent of local regulation varies by state; some states preempt local regulation of oil and gas development, with limited exceptions for road use and limited zoning,[54] while others, such as Texas,[55] allow extensive local controls. Local regulation is not discussed in depth in this paper. Readers should refer to other sources for further detail on preemption, municipalities' expanding efforts to control shale gas development, and other local regulatory issues.[56]

Regardless of whether a state has preempted local authority over oil or gas development, states have the bulk of the regulatory responsibility over shale gas development; they both administer federal environmental regulations and write and enforce a range of state oil and gas regulations, including, among others, regulations addressing the location of wells, water withdrawals, maintenance of pits for temporary containment of oil and gas waste, disposal of waste, and site remediation. Although states have primary regulatory authority over oil and gas development, a

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[53] *See, e.g.*, Arlington, Texas, Ordinance No. 07-074 § 7.01 A.29 (2007), *available at* http://www.marcellus-shale.us/pdf/Gas-Drill-Ord_Arlington-TX.pdf; Fort Worth, Texas, Ordinance No. 18449-02-2009 § 15-42 A.2 (2009), *available at* http://www.fortworthgov.org/uploadedFiles/Gas_Wells/090120_gas_drilling_final.pdf.

[54] *See* N.Y. Envtl. Conserv. Law § 23-0303(2) (McKinney 2010); 58 Pa. Cons. Stat. Ann. § 601.602 (West 2010) (preempting most local regulation of oil and gas development). *But see* Huntley & Huntley, Inc. v. Borough Council of Oakmont, 964 A.2d 855, 865–69 (Pa. 2009) (suggesting that local governments in Pennsylvania may, at minimum, designate the zones within which oil and gas extraction may occur).

[55] *See supra* note 53.

[56] *See, e.g.*, Michelle L. Kennedy, Essay, The Exercise of Local Control Over Gas Extraction, 22 FORDHAM ENVTL. L. REV. 375 (2011); Bruce M. Kramer, *Local Land Use Regulation of Extractive Industries: Evolving Judicial and Regulatory Approaches*, 14 UCLA J. ENVTL. L. & POL'Y 41 (1995/96).

number of federal regulations apply to the development process. Clean Water Act stormwater controls aim to minimize erosion and sedimentation during construction (including construction of oil and gas sites), and the Clean Water Act prohibits the dumping of any pollutant into U.S. waters without a permit.[57] The EPA intends to propose Clean Water Act standards for the treatment of wastewater from shale gas wells in 2014.[58] Further, under recently-proposed Clean Air Act regulations, shale gas operators also will have to control volatile organic compound (VOC) emissions from flowback during the fracturing process by using a VOC capture technique called "green completion."[59] Shale gas operators also must comply with the Endangered Species Act (ESA), the Migratory Bird Treaty Act (MBTA), and certain portions of the Emergency Planning and Community Right-to-Know Act (EPRCA)[60] and the Occupational Safety and Health Act (the OSHAct),[61] among other federal acts. Under the ESA, operators must consult with the Fish and Wildlife Service and potentially obtain an incidental "take" permit if endangered or threatened species will be affected by well development.[62] Operators will be strictly liable for any harm to migratory birds under the MBTA and therefore must ensure that their maintenance of surface pits or their use of rigs does not attract and harm these birds.[63] Under EPCRA and the OSHAct, in turn, operators must maintain material safety data sheets

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[57] 33 U.S.C. § 1311 (2011) (making unlawful the discharge of any pollutant except in compliance with the Act); 33 U.S.C. § 1342 (2011) (allowing the EPA Administrator to issue a permit for the discharge of a pollutant)

[58] EPA Announces Schedule to Develop Natural Gas Wastewater Standards, Oct. 201, 2011, http://yosemite.epa.gov/opa/admpress.nsf/bd4379a92ceceeac8525735900400c27/91e7fadb4b114c4a8525792f00542001!OpenDocument.

[59] Environmental Protection Agency, Proposed Rule, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 76 Fed. Reg. 52738, 52758 (Aug. 23, 2011) (requiring "reduced emission completion" ("green completion") and pit flaring for new hydraulically fractured and refractured wells).

[60] See Emergency Planning and Community Right-to-Know Act of 1986 §§ 312–313, 42 U.S.C. §§ 11021–11022 (2006) (requiring material safety data sheets and hazardous chemical inventory forms when certain quantities of hazardous chemicals are present at facility). This information is extracted from Hannah Wiseman, *Trade Secrets, Disclosure, and Dissent in a Fracturing Energy Revolution*, 111 COLUM. L. REV. SIDEBAR 1 (2011), http://www.columbialawreview.org/assets/sidebar/volume/111/1_Wiseman.pdf.

[61] Hazard Communication, 52 Fed. Reg. 31,852 (Aug. 24, 1987); 29 C.F.R. § 1910.1200(b) (2010) (requiring "all employers to provide information to their employees about the hazardous chemicals to which they are exposed").

[62] 16 U.S.C. § 1538 (a) (2011).

[63] 16 U.S.C. § § 703, 707 (2011).

(MSDS) for certain hazardous chemicals that are stored on site in threshold quantities.[64] Finally, under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), operators must report releases of hazardous chemicals of threshold quantities[65] and may potentially be liable for cleaning up these spills.[66]

Oil and gas operators, while facing a number of local, state, regional, and federal regulations, also enjoy several federal exemptions. Most wastes ("exploration and production" or "E&P" wastes) from fracturing and drilling are exempt from the hazardous waste disposal restrictions in Subtitle C of the Resource Conservation and Recovery Act (RCRA),[67] meaning that states—not the federal government—set the required disposal procedures for the waste. Although Subtitle C of RCRA originally covered oil and gas wastes—thus requiring that oil and gas operators follow federally-established procedures for handling, transporting, and disposing of the wastes—in the 1980s Congress directed the EPA to prepare a report on oil and gas wastes and determine whether they should continue to be federally regulated.[68]

In its report, the EPA noted that some of the wastes were hazardous but ultimately determined that due to the economic importance of oil and gas development and state controls on the wastes, federal regulation under RCRA Subtitle C was unwarranted.[69] The EPA did note some state regulatory deficiencies in waste control, however, and relied on the development of a voluntary program to improve state regulations. This voluntary program has since emerged as the State Review of Oil and Natural Gas Environmental Regulations (STRONGER)—a non-profit partnership between industry, nonprofit groups, and regulatory officials[70] that has developed

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[64] 42 U.S.C. 11005 (2011); Emergency Planning and Community Right-to-Know Act of 1986 §§ 312–313, 42 U.S.C. §§ 11021–11022 (2011).

[65] 42 U.S.C. § 9603(a) (2011).

[66] 42 U.S.C. § 9607 (2011).

[67] 53 Fed. Reg. 25,446-01, 25,447 (July 6, 1988) (exempting these wastes from Subtitle C of RCRA).

[68] For a full discussion of the process of the exemption, *see* Hannah Wiseman, *Regulatory Adaptation in Fractured Appalachia*, 21 VILL. ENVTL. L.J. 229, 243-48 (2010).

[69] 53 Fed. Reg. 25,446 (1988).

[70] State Review of Oil and Natural Gas Environmental Regulations, http://www.strongerinc.org/.

guidelines for state regulation of oil and gas wastes, periodically reviews state regulations, and encourages states to improve certain regulations.[71] Despite the RCRA exemption, some states treat oil and gas wastes as unique wastes under their own waste disposal acts. Pennsylvania, for example, treats certain oil and gas wastes (including flowback water from fracturing) as "residual" wastes under its state Solid Waste Management Act and has special handling and disposal requirements for these wastes.[72] Furthermore, in all states, non-exempt oil and gas wastes, such as unused hydraulic fracturing fluids and other oil and gas wastes that tend to have higher levels of hazardous substances,[73] still must be disposed of in accordance with federal RCRA requirements.[74]

The Comprehensive Environmental Response, Compensation, and Liability Act also contains an exemption for oil and gas. CERCLA holds owners and operators of facilities, those who arrange

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[71] For more description of the exemption and the EPA's reliance on this private nonprofit group to encourage better state regulations, see Guidelines for the Review of State Oil & Natural Gas Environmental Regulatory Programs, *supra* note 46, at §§ 1.1-1.3.1. If the reader wishes to learn more about the role of the State Review of Oil and Natural Gas Environmental Regulations (STRONGER), *see* STRONGER, http://www.strongerinc.org/ "The state review process is a collaborative process by which review teams composed of stakeholders from the oil and gas industry, state environmental regulatory programs, and members of the environmental/public interest communities review state oil and gas waste management programs against a set of Guidelines developed and agreed to by all the participating parties."). For STRONGER's general guidelines for oil and gas development, which suggest, for example, how operators should construct and maintain surface pits among many other suggested standards, *see* STRONGER, Revised Guidelines, *available at* http://www.strongerinc.org/documents/Revised%20guidelines.pdf. For STRONGER's recently-developed hydraulic fracturing-specific guidelines, *see* Memorandum from the STRONGER Board to Persons Interested in the Hydraulic Fracturing Guidelines, Feb. 8, 2010, Update on the Development of Hydraulic Fracturing Guidelines, *available at* http://www.strongerinc.org/documents/HF%20Guideline%20Web%20posting.pdf.

[72] 25 Pa. Code § 287.1 (West 2011) (defining "residual waste" as "Garbage, refuse, other discarded material or other waste, including solid, liquid, semisolid or contained gaseous materials resulting from industrial, mining and agricultural operations and sludge from an industrial, mining or agricultural water supply treatment facility, wastewater treatment facility or air pollution control facility, if it is not hazardous."); 25 Pa. Code § 287.1 (West 2011); 25 Pa. Code § 287.53-54 (West 2011) (requiring generators that produce an average of 2,200 pounds of waste monthly to employ "source reduction strategies" and to characterize the chemical composition of their waste).

[73] For a list of oil and gas exploration and production wastes that are not exempt from Subtitle C of RCRA, see U.S. Envtl. Protection Agency, Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations 11 (2002), *available at* http://epa.gov/osw/nonhaz/industrial/special/oil/oil-gas.pdf.

[74] *See, e.g.*, Arkansas Oil and Gas Commission Rule B-26 (2011) ("All stormwater and produced fluids which have been mixed with non-exempt RCRA waste as defined by the USEPA shall be removed and disposed in accordance with applicable Pollution Control and Ecology Commission regulations, as administered by ADEQ.").

for disposal of waste, and those who accept hazardous substances for disposal liable for the costs of hazardous substance clean-up,[75] and the Act also requires reporting of certain hazardous waste spills.[76] CERCLA exempts oil and natural gas from the hazardous substances that trigger these liability and reporting requirements,[77] however. Oil and gas operators still must report spills of other hazardous substances of a threshold quantity (those that are not oil and gas) and ultimately may be liable for clean-up of these wastes.

A third oil and gas exemption from environmental regulation is contained in the Clean Water Act. Typically, industrial facilities that generate stormwater runoff (as "pollutant" under the Act) must obtain a stormwater permit under the Clean Water Act for this runoff; they are required to have a permit both for constructing the facility (at which point soil sediment may run off the site) and operating it (at which point polluted substances may continue to run off the site during precipitation events, for example). The Clean Water Act does not require oil and gas operators, however, to obtain a permit for uncontaminated "discharges of stormwater runoff from . . . oi l and gas exploration, production, processing, or treatment operations."[78] In the Energy Policy Act of 2005 (EPAct 2005), Congress expanded the definition of oil and gas exploration and production under the Clean Water Act[79]--a definitional change that potentially allowed for the exemption of more oil and gas activity from stormwater permitting requirements. The EPA subsequently revised its regulations to exempt oil and gas *construction* activities from the NPDES stormwater permitting requirements.[80] In 2008, the United States Court of Appeals for

[75] 42 USC § 9607 (West 2011).

[76] 42 U.S.C. 9603 (West 2011); 42 U.S.C. 9602 (2011) (providing threshold amounts for the spill reporting requirement).

[77] 42 U.S.C. § 9601(14) (2011) (exempting from the definition of "hazardous substance" "petroleum, including crude oil or any fraction thereof" and "natural gas, natural gas liquids, liquefied natural gas, or synthetic gas usable for fuel").

[78] 33 U.S.C. § 402(l)(2) (West 2011).

[79] 33 U.S.C. § 1362(24) (West 2011).

[80] Envtl. Protection Agency, Regulation of Oil and Gas Construction Activities, http://cfpub.epa.gov/npdes/stormwater/oilgas.cfm (last updated Mar. 9, 2009).

the Ninth Circuit in *Natural Resources Defense Council v. EPA* vacated these regulations.[81] The EPA has since reinstated its prior requirements for stormwater permits along with "clarification" based on EPAct 2005.[82] In sum, oil and gas operators must obtain a stormwater permit under the Clean Water Act for the construction of a well pad and access road that is one acre or greater, but they need not obtain such a permit for any uncontaminated stormwater from the drilling and fracturing operation. Some states, such as New York, and regional entities, such as the Delaware River Basin Commission (a governmental body formed by an interstate compact and tasked with protecting the quality of surface water within the basin), have proposed to require stormwater permitting that addresses both the construction of oil and gas pads that will host hydraulically fractured wells and the operations that occur on those pads.[83]

Finally, fracturing operations also are exempt from the Safe Drinking Water Act (SDWA), which requires entities that inject substances underground to prevent groundwater pollution. The SDWA applies only to waste from fracturing and drilling that is disposed of in underground injection control wells;[84] an SDWA underground injection control (UIC) permit is not required for the fracturing operation itself. Operations that use diesel fuel in fracturing, however, are not exempt from SDWA.[85] The EPA currently is developing UIC standards for fracturing with diesel.[86]

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[81] *Natural Resources Defense Council v. United States Environmental Protection Agency*, 526 F.3d 591 (9th Cir. 2008).

[82] Envtl. Protection Agency, Regulation of Oil and Gas Production Activities, http://cfpub.epa.gov/npdes/stormwater/oilgas.cfm (last updated Mar. 9, 2009).

[83] NY Preliminary Revised SGEIS at 7-26-7-27.

[84] 42 U.S.C. § 300h (d)(1) (2011).

[85] *Id*. (excluding from the SDWA definition of underground injection "the underground injection of fluids or propping agents (*other than diesel fuels*) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities" (emphasis added)).

[86] EPA, Underground Injection Control Guidance for Permitting Oil and Natural Gas Hydraulic Fracturing Activities Using Diesel Fuels, http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_hydroout.cfm#diesel.

As result of the federal exemptions for oil and gas development and historic state authority over oil and gas development, the majority of regulation of the development process occurs at the state level, as discussed in the following section.

4 Content of State Regulations That Apply to Shale Gas Development, With Some Discussion of Local and Regulation

This section compares regulations in sixteen states that currently are producing gas or oil from shales or gas from tight sands formations or soon will. It provides examples of regulations at each stage of the well development process—roughly in order of the development stages of a shale gas, shale oil, or tight sands well—and explores the potential environmental effects addressed by these regulations. This section also describes, where relevant, local and regional regulation. In each of the tables below, a reference to "DRBC" describes the Delaware River Basin Commission, and "SRBC" describes the Susquehanna River Basin Commission. These Commissions are regional entities (approved by Congress, as required by the Compact Clause of the U.S. Constitution)[87] with authority over the water quality and quantity in these rivers—including the respective watersheds that affect water quality and quantity. Their regulations apply in portions of New York and Pennsylvania, as well as other Appalachian states. Although regional regulations are not directly transferable to many states in light of their different objectives and powers,[88] they offer useful examples and add to the set of regulatory experimentation from which federal, state, and local entities may glean both positive and negative lessons. To avoid repetition, the authors included regional regulations within only one cell of the relevant comparison tables (under New York or Pennsylvania); note that these regulations apply in portions of both New York and Pennsylvania, however. The Delaware River Basin Commission regulations described in some tables below are proposed and have not yet been implemented. A lawsuit filed by the State of New York, which claims that the DRBC must prepare an environmental impact statement under the National Environmental Policy Act before

[87] *See* Delaware River Basin Compact, 1961, *available at* http://www.state.nj.us/drbc/regs/compa.pdf; Susquehanna River Basin Compact, 1972, *available at* http://www.srbc.net/about/srbc_compact.pdf.

[88] The Delaware River Basin Commission has jurisdiction in portions of Delaware, New Jersey, New York, and Pennsylvania. *See id*. The Susquehanna River Basin Commission has jurisdiction in portions of Maryland, New York, and Pennsylvania. *See* Susquehanna River Basin Compact (1972), *available at* http://www.srbc.net/about/srbc_compact.pdf.

finalizing the regulations, also may delay their effect.[89] **Finally, none of the regulatory comparison tables in this paper are comprehensive**. A blank box within a table does not definitively indicate that the state lacks regulation in the area addressed, but rather that the authors have not yet summarized and/or located the regulation.

4.1 Testing for Gas

An operator who plans to develop a shale gas well must first locate the productive areas of gas. Typically, a team of geophysicists using "seismic testing" techniques already will have mapped out an area and will offer Seismic techniques vary substantially,[90] but, as generally understood, they require three stages, including acquiring data in the form of underground reverberations from rock formations, processing the data through a machine such as a seismograph or geophone, and interpreting the data.[91] To acquire reverberations from underground formations, a team of geophysicists either sets off an explosive in holes in the ground called shot holes, detonates explosives at the surface, or strikes the surface with heavy equipment in a technique called "vibroseis."[92] The loud sound created by blasting or striking the ground "travels downward into the ground and reflects off of strata (reflectors) back to the surface, creating an echo."[93] This sound travels through different types of underground strata at different velocities, and this allows geophysicists to identify the depths of various subsurface materials, from sandstone or clay to salt, methane, and oil.[94] The company also may use a more simple technique to locate likely

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[89] New York v. Army Corps of Engineers, Complaint, May 31, 2011, *available at* http://www.ag.ny.gov/media_center/2011/may/DRBC%20Complaint%20%28Final%29.pdf.

[90] *See* Anderson & Piggot, *supra* note 23, at 12 (describing differences between acquisition of seismic data for 3D (three-dimensional) and 2D seismic testing, including the use of more sources (points of sound, such as explosions) and receivers (machines that pick up the seismic data) for 3D testing.

[91] *See* Anderson & Piggot, *supra* note 23, at 5, 12. *See also See* N.Y. Dep't of Envtl. Conservation, Guidelines for Seismic Testing on DEC Administered State Land (Dec. 20, 2007), *available at* http://www.dec.ny.gov/docs/lands_forests_pdf/sfseismic.pdf (describing various methods of conducting seismic testing, including

[92] *See* Anderson & Piggot, *supra* note 23, at 12 (mentioning explosives and vibroseis); N.Y. Dep't of Envtl. Conservation, *supra* note 91, at 1 (describing shot holes, surface shots, and vibroseis).

[93] Anderson &. Piggot, *supra* note 23, at 5.

[94] *Id*. at 8.

locations of underground gas by drilling a stratigraphic test well, which is not used to produce oil or gas but rather helps the operator determine the quantity and quality of oil or gas at a given location.[95]

Many states require operators to obtain a permit and/or a blaster's license before blasting a shot hole or conducting other seismic testing,[96] but beyond this preliminary measure, safety and environmental protections vary widely. Maryland and Louisiana have some of the most comprehensive environmental protections at this stage. Maryland requires assurances that the testing will not impact environmental resources and allows its environmental agency to deny a blasting permit if there is a substantial risk of unmitigated environmental damage from the blasting. Maryland also allows permit denial if blasting would affect Chesapeake Bay resources and other water resources. [97] Louisiana, in turn, requires entities proposing seismic testing to work under the supervision of the Seismic Section of the Department of Wildlife, and North Dakota mandates minimum distances between blasting and natural resources such as springs. As summarized in Table 1, several states also require that shot hole blasting or other seismic testing not occur within a certain distance of water wells and other potentially sensitive resources, and that the shot hole be plugged following the completion of testing. Colorado has some of the most detailed plugging regulations for shot holes, which vary depending on whether artesian or non-artesian water flows were encountered during blasting.[98] New York, in contrast, appears to have

[95] *See, e.g.*, North Dakota 43-02-03-01 Oil and Gas Conservation ("Stratigraphic test well" means any well or hole, except a seismograph shot hole, drilled for the purpose of gathering information in connection with the oil and gas industry with no intent to produce oil or gas from such well."

[96] *See, e.g.*, Explosives Regulations of the Colorado State Division of Oil and Public Safety § 3.1, http://www.colorado.gov/cs/Satellite?blobcol=urldata&blobheader=application%2Fpdf&blobkey=id&blobtable=MungoBlobs&blobwhere=1251616366954&ssbinary=true (prohibiting anyone from using explosives without first obtaining a permit from the Division of Oil and Public Safety); 25 Pa. Code § 210.13 (2011) ("A person may not detonate explosives or supervise blasting activities unless the person has obtained a blaster's license."); 25 Pa. Code § 211.121 (2011) (providing that "a person may not engage in blasting activities . . . without first obtaining the appropriate permit from the Department issued under this chapter.").

[97] MD ADC § 26.19.01.03 (2011).

[98] *See infra* Table 1.

few protections at the seismic testing stage, aside from protections on state lands.[99] New York has not addressed this aspect of the oil or gas development process in its Supplemental Generic Environmental Impact Statement[100]—a document that will impose a range of protective conditions on "high volume" hydraulic fracturing in shales (fracturing that requires large volumes of water).

Several environmental risks are present at the seismic testing stage. Large seismographic trucks that strike the ground to create vibrations (sometimes called "thumper trucks") could compact soils and damage water resources if they cross streams and wetlands, for example. Blasting of shot holes in sensitive environmental areas could potentially damage surface and underground water sources, and unplugged shotholes could, in addition to posing a basic safety risk, potentially allow for underground intrusion of pollutants. States that do not provide for agency review or, at minimum, agency notification of blasting in environmentally sensitive areas should consider adding regulatory controls in this area. All states, following the lead of Arkansas, Colorado, Louisiana, Montana, North Dakota, and Texas, also should require that shot holes be plugged. Tables 1a and 1b show minimum required distances between seismic testing and environmental and domestic resources for the following:

- Location of shot holes and other seismic activity
- Other seismic protections

[99] *See* N.Y. Dep't of Envtl. Conservation, Guidelines, *supra* note 92.
[100] New York Dep't of Envtl. Conservation, Preliminary Revised Supplemental Generic Environmental Impact Statement.

Table 1a. Minimum required distances between seismic testing and environmental and domestic resources: Location of shot hole/other seismic activity

AR	No shot hole w/in 200 ft. of residence, water well, structure w/out express authority; peak; other required distances from structures vary based on charge weight. AOGC Rule B-42(k) (2010)
CO	Minimum distance requirements for storage of explosives only. 7 COLO. CODE REG. § 1101-9:4.6, 8.1 (West 2011) (explaining that ch. IV applies to seismic blasting)
KY	Provides "maximum peak particle velocity of the ground motion" "at the immediate location of any dwelling house, public building, school, church, commercial or institutional building." 805 KY. ADMIN. REGS. 4:020 (West 2011)
LA	"Explosives shall not be detonated in congested areas or in close proximity to any structure, railway, highway, pier, dock, vessel, or other installation which may be damaged." LA ADC 55:I: 1531 (2011). No explosives w/in 1,000 ft. of a boat. LA. ADMIN. CODE tit. 76, pt. I., § 301 (West 2011)
MD	No blasting w/in 500 ft. of occupied building w/out written permission. Md. Code Regs. 26.19.01.04
MI	*Search did not locate statute, regulation, or policy addressing this issue.*
MT	No vibroseis w/in 330 feet or shot hole w/in 1320 ft. of "any building, structure, water well, or spring"; not w/in 660 ft. of reservoir dam w/out written permission. MONT. ADMIN. R. 36.22.501 (West 2011)
NM	*Our search did not locate statute, regulation, or policy addressing this issue.*
NY	On state lands, 250 feet from existing roads and trails. Guidelines for Seismic Testing on DEC Administered State Land Dec. 12, 2007, http://www.dec.ny.gov/docs/lands_forests_pdf/sfseismic.pdf
ND	No seismic shot hole blasting less than 600 ft. and no nonexplosive exploration methods less than 300 feet from "from water wells, buildings, underground cisterns, pipelines, and flowing springs," except by written agreement. N.D. ADMIN. CODE 43-02-12-05 (West 2011)
OH	The Ohio Department of Natural Resources "does not regulate seismic activity."[101]
OK	No seismic activity w/in 200 ft. of water well w/out written permission; not w/in 500 ft. of Superfund site boundary. OHIO ADMIN. CODE 165:10-7-15 (West 2011)
PA	"Maximum allowable peak particle velocity" limitation (or minimum scaled distance requirement) at "closest building or other structure" 25 PA. CODE 211.151 (West 2011)
TX	Drilling permit required for seismic holes that penetrate a "depth or depths at which usable quality water must be protected or isolated." 16 TEXAS ADMIN. CODE § 3.100 (West 2011)
WV	Blasting regulations appear to apply only to "surface mining operations" and "surface disturbances associated with underground mining operations." W. VA. CODE R. § 199-1-1 (West 2011)
WY	No shot holes w/in ¼ mile of building or water well; no "vibroseis, seismic operations" w/in 300 ft. of building or water well. WYO. CODE. R. OIL GEN Ch. 4 s 6(q) (West 2011)

[101] Ohio Department of Natural Resources, Oil and Gas Frequently Asked Questions, http://www.ohiodnr.com/oil/oilfaq/tabid/17869/Default.aspx (last visited Sept. 12, 2011).

Table 1b. Minimum required distances between seismic testing and environmental and domestic resources, other seismic protections

AR	Proper backfill of hole required, no cutting of tree 6" or more in diameter unless no reasonable alternative. AOGC RULE B-42 (m),(p) (2010)
CO	Must rake slurry, drilling fluids, cuttings from shot hole to w/in 1 inch of surface; plugging and filling of all shot holes required, differs by whether artesian or non-artesian water flow encountered. 2 Colo. Code Reg. § 404-1, Rule 333 (West 2011)
KY	*Appears to have no setback requirement; other protections not located.*
LA	No geophysical exploration work w/out first notifying Wildlife and Fisheries Commission. Marsh vehicles, if used, must cause minimum disturbance. Must backfill shot hole w/ cuttings and plug. Seismic activities must be under supervision of Seismic Section of Dep't of Wildlife. LA ADC 76:I.301
MD	Md. DEP may deny seismic permit if testing will "poses a substantial risk of causing environmental damage that cannot be mitigated by the applicant." MD. CODE ANN., ENVT., § 14-109 (2011)
MI	*Appears to have no setback requirement; other protections not located.*
MT	Must plug shot holes. MONT. ADMIN. R. 82-1-104 (West 2011)
NM	*Appears to have no setback requirement; other protections not located.*
NY	*Appears to have no setback requirement; other protections not located.*
ND	Plugging required. N.D. ADMIN. CODE 43-02-12-07 (West 2011)
OH	*Appears to have no setback requirement; other protections not located.*
OK	*Appears to have no setback requirement; other protections not located.*
PA	Blasting may not damage real property, with the exception of the property of the blasting permittee. 25 PA. CODE § 211.151 (West 2011)
TX	Plugging and letter of protection depth from TCEQ required. 16 TEX. ADMIN. CODE § 3.100 (West 2011)
WV	*Appears to have no setback requirement; other protections not located.*
WY	Must be plugged on same day shot hole has been drilled and loaded. WY ADC OIL GEN Ch. 5 s 6(q) (2011)

4.2 Constructing a Well Pad and Access Road: Preventing Erosion and Sedimentation Throughout the Drilling and Fracturing Process; Protecting Wildlife and Minimizing Habitat Fragmentation

After an operator has located a site for drilling and collected the necessary mineral rights through a lease and drilling and other required permits from state and/or federal agencies, the operator constructs a well pad and an access road to the pad. Access roads for shale gas development may cover 0.1 to 2.75 acres, and well pads typically range between 2.2 and 5.7 or more acres,[102] with an average shale gas well pad size (industry estimate) of 3.5 acres.[103] This stage of the development process leads to increased stress on l ocal roads, potential erosion and sedimentation, potential surface pollution from equipment leakage (diesel and other substances), and direct and indirect impacts on wildlife, including habitat fragmentation.[104]

As introduced in part A. above, under the Clean Water Act, shale gas operators must obtain general stormwater permits for constructing access roads and well pads. States implement Clean Water Act requirements, including stormwater permitting, and many states approve the construction of a shale gas site under a "general industrial" stormwater permit or similar erosion and sediment control plan.[105] Under this general permit, which requires stormwater controls that are not individualized by site, the operator must submit a notice of intent to the state, and the state must grant general permit approval before construction may begin. Under the general

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[102] NEW YORK STATE DEP'T. OF ENVTL. CONSERVATION, REV. SGEIS, *supra* note 4, at 5-10. In New York State, gas companies have applied to drill and hydraulically fracture for natural gas in the Marcellus Shale formation that lies beneath the state. Out of those applications, "[p]roposed well pad sizes range from 2.2 to 5.5. acres" (excluding the access road), and New York's Department of Environmental Conservation believes that these sizes are "consistent" with sizes required for drilling and fracturing in other formations, such as a n average 3.6-acre pad in Wyoming (excluding the access road) and a maximum of 5.7 acres in the Fayetteville Shale of Arkansas. *See also* Frantz, *supra* note 24, at 4 (estimating a "footprint" of "3-5 acres").

[103] NEW YORK STATE DEP'T. OF ENVTL. CONSERVATION, REV. SGEIS, *supra* note 4, at § 5.1.2.

[104] *Id*. at §5.1, 6.1.2, 6.1.3, 6.4.1.

[105] *See, e.g.*, Arkansas Rule B-17 (requiring a "stormwater erosion and sediment control plan" for each well site, which must "describe and ensure the implementation of both erosion and sediment control practices which are to be used to reduce pollutants in stormwater discharges associated with the well pad and access roads," and alternatively allowing the operator to follow a guidance document for sediment controls); *See* MD. CODE REGS. 26.19.01.06 C(12)-(13) (2009) (requiring a "sediment and erosion control plan" and a "stormwater management plan"); W. VA. CODE ANN. § 22-6-6(d)(LexisNexis 2010) (requiring a "soil erosion control plan").

permit, operators constructing well pads and access roads typically must follow best management practices (BMPs) under those permits.[106] These BMPs help to control erosion and sedimentation during the well pad and access road construction process,[107] and they tend to have similar content in all sixteen states described in this paper. Most require controls such as water bars to prevent water from running directly down a road and creating a gully, silt fences, and culverts. Some states also encourage operators to use existing roads as access roads to avoid surface disturbance and erosion.[108]

Unique Delaware River Basin stormwater controls are being considered by the Delaware River Basin Commission, which has proposed to regulate many stages of shale gas development. For the construction of well pads in the drainage areas of "Special Protection Waters" in the Basin, for example, the Commission has proposed that operators must implement a Non-Point Source Pollution Control Plan. The proposal contains some of the most stringent stormwater measures described in Table 2 below.[109] The proposal calls for the plan to be approved before any clearing for well pad or access road construction begins. The plan must include both pre-and post-construction stormwater controls, including stormwater structures (some permanent, if necessary) that will control runoff during the construction and operation of the well and after site restoration is complete. The plan's erosion control measures must include the more stringent of two measures: those contained in state regulations or those found in the Delaware River Basin Commission's Water Quality Regulations.[110]

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[106] *See, e.g.*, Pennsylvania Department of Environmental Protection, Instructions for a Notice of Intent (NOI) for Coverage Under the Erosion and Sediment Control General Permit (ESCGP-1) For Earth Disturbance Associated with Oil and Gas Exploration, Production, Processing or Treatment Operations or Transmission Facilities, *available at* http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-83401/Modified%205500-PM-OG0005%20NOI%20Instructions%202.pdf.

[107] Portions of this paragraph were originally prepared by Hannah Wiseman for CLE International, Oklahoma Water Law, May 5-6, 2011, Hydraulic Fracturing and Water Quality: A Brief Description of Regulations.

[108] *See, e.g.*, COGCC Rule 1002.

[109] Delaware River Basin Comm'n, Proposed Natural Gas Development Regulations, Dec. 9, 2010, at 59-60, *available at* 41.

[110] *Id*.

In addition to controlling soil erosion during the construction of an access road and well pad on which oil and gas development activities will occur, some states have recognized the potential impacts of construction on wildlife, including indirect impacts such as habitat fragmentation. Colorado has some of the most protective measures in this area. If a proposed well will be within a "sensitive wildlife habitat or a restricted surface occupancy area," the operator must consult with the Colorado Division of Wildlife, the Colorado Oil and Gas Conservation Commission (COGCC Director), and the Surface Owner about potential wildlife impacts. The COGCC director may impose various conditions of approval, which shall be "guided by the list of Best Management Practices for Wildlife Resources" identified on the COGCC's website.[111] Colorado gives operators an option to submit a Comprehensive Drilling Plan to the Colorado Oil and Gas Conservation Commission, and the Colorado Department of Public Health and Environment, the Colorado Division of Wildlife, "local government designee(s)," and affected surface owners all are invited to participate in developing the plan. "In many cases, participation by these agencies and individuals will facilitate identification of potential impacts and development of conditions of approval to minimize adverse impacts."[112] The plan remains valid for six years. Colorado also attempts to minimize surface disturbance and habitat fragmentation by providing, "Where possible, operators shall provide for the development of multiple reservoirs by drilling on existing pads or by multiple completions or commingling in existing wellbores."[113]

Other states require few specific wildlife or habitat protections but simply remind oil and gas operators that construction and operation of an oil or gas production site may harm endangered species and may require various permits and consultations under the Endangered Species Act. Kentucky, for example, provides that no "waste site or facility" (which includes a "holding pit" for produced water[114]), shall "[c]ause or contribute to the taking of any [ESA-listed] endangered

[111] COGCC Rule 1202 (b)-(c)
[112] COGCC Rule 216d.
[113] 2 CCR 404-1 Rule 603(d) (2011).
[114] 401 KAR § 5:090 Section 9(a) (2011) ("Holding pits shall be constructed in accordance with KRS Chapter 151 and Division of Waste Management administrative regulation 401 KAR 30:030.").

or threatened or candidate species" or "[r]esult in the destruction or adverse modification of the critical habitat of" these species.[115] Several states also require that certain surface pits be covered by netting (a measure noted in Section 11 – "Storing Wastes").[116] As oil and gas drilling increases in areas not previously subject to exploration—due largely to the advancement of fracturing technologies—states should consider how drilling and fracturing may affect sensitive areas. They should consider implementing controls to reduce surface disturbance (for example, requiring operators to use existing roads, where available). States also should explore the option of requiring site-specific permitting or best management practices in sensitive wildlife areas, and updating stormwater permits to recognize the heavier site traffic and potential surface disturbance that occurs as a result of fracturing. Furthermore, states should encourage operators to locate access roads and well pads away from sensitive areas; horizontal drilling, which allows an operator to drill laterally through shale for several thousand feet, makes this possible. As the National Park Service has noted in the context of the Marcellus Shale:

> While the horizontal drilling and hydraulic fracturing practices expected to be used in developing the Marcellus Shale have negative environmental effects on the surrounding area, when compared to development of conventional oil and gas resources this development method could result in fewer impacts than conventional vertical wells due to greater flexibility in well location.[117]

Table 2 provides examples of state stormwater permitting requirements for well pad and access road construction—a stage of the well development process that applies to all wells, not just hydraulically fractured ones.

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[115] 401B KY ADC § 30:031 Section 3 (2011).

[116] *See, e.g.*, N.D. Admin. Code § 43-02-03-19.1 (2011).

[117] Nat'l Park Service, Potential Development of the Natural Gas Resources in the Marcellus Shale 4 (Dec. 2008), *available at* http://www.eesi.psu.edu/news_events/EarthTalks/2009Spring/materials2009spr/NatParkService-GRD-M-Shale_12-11-2008_view.pdf.

Table 2. Examples of stormwater management regulations: Stormwater permits and best management practices

AR	Erosion and sediment control plan or ADEQ-approved guidance document; site-specific permit if will discharge to CWA (303(d)) or other certain water bodies. AOGC Rule B-17(l) (2010)
CO	Construction stormwater and post-construction stormwater permits, which include BMPs for "transport of chemicals and material"; no post-construction controls for Tier 1 O&G sites (slope less than 5%, low erosion risk). 2 CCR 404-1 Rule 1002(f) (2011)
KY	General permit for stormwater discharges[2] [118]
LA	LWDPS permit required for stormwater runoff from exploration and production activities not upland; limits on chemical oxygen demand, organic carbon, chloride, oil and grease in stormwater. La. Admin. Code 33:IX.708 (2011)
MD	Sediment and erosion control plan and stormwater plan required. COMAR 26.19.01.06(C) (2011)
MI	Counties issue Soil Erosion and Sedimentation Control permits. [119]
MT	General Permit for Storm Water Discharges Associated with Mining, Oil and Gas Activities, including exploration and production. [120]
NM	EPA appears to issue permits for oil and gas stormwater. [121]
NY	New stormwater general permit for gas drilling operations (in addition to general stormwater construction), individual State Pollutant Discharge Elimination System permit for stormwater discharges w/in 500 ft. of principal aquifers. R SGEIS at 7.1.2
ND	General stormwater permit for five acres of more. [122]
OH	Erosion and control BMPs required in urbanized areas. OH ADC 1501:9-1-07 (B) (2011)

[118] *See* Energy and Env't Cabinet, Kentucky Dep't of Envtl. Protection, Fact Sheet, Kentucky Pollutant Discharge Elimination System (KPDES) General Permit for Stormwater Discharges Associated with Construction Activities (KYR10), *available at* http://water.ky.gov/permitting/General%20Permit%20Fact%20Sheets/FinalPermitKYR10000RTC_2_.pdf (mentioning plans for oil and gas exploration and production as potentially requiring a general permit).

[119] *See* Michigan Dep't of Envtl. Quality, Soil Erosion and Sedimentation Control Agencies, http://www.michigan.gov/deq/0,4561,7-135-3311_4113-8870--,00.html.

[120] Montana Dep't of Envtl. Quality, Storm Water Discharges Associated with Oil, Gas, and Mining Activity, http://deq.mt.gov/wqinfo/MPDES/StormwaterMining.mcpx.

[121] New Mexico Env't Dep't, Environment Secretary Discussed Oil and Gas Industry Exemptions from environmental Law and Regulations at ABA Conference in Dallas, June 18, 2010 (explaining, in the context of stormwater discharges from oil and gas activities, that "EPA regulates NPDES permits for New Mexico").

[122] *See* Fact Sheet, Stormwater Discharges from Construction Activities North Dakota Pollutant Discharge Elimination System (NDPDES) General Permit NDR 10-0000, http://www.ndhealth.gov/wq/storm/Construction/NDR10sob20091001F.pdf.

OK EPA-issued stormwater permits for oil and gas drilling and production.[123]

PA Erosion and Sediment Control and Stormwater Management for Oil and Gas Exploration, Production, Processing, Treatment Operations or Transmission Facilities General Permit (ESCGP-1) for all earth disturbances 5 acres or greater[124] (Marcellus Advisory Commission indicates that E&S plan is required for all disturbances of 5,000 square feet or greater or any disturbance with the potential to discharge sediment to certain waters with very good water quality.[125]

TX Stormwater discharges authorized by EPA and Railroad Commission when required by federal law. 16 TAC 3.30 (b)(1)(B)(ii) (2011).

WV BMPs in Erosion and Sediment Control Manual.[126]

WY NPDES Small Storm Water Construction permit from Wyoming DEQ Storm Water Division and storm water pollution prevention plan for development between 1 and 5 acres on federal lands; NPDES Large Storm Water Construction and storm water pollution prevention plan for wells on five acres or more.[127]

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[123] Okl. Dep't of Envtl. Quality Water Quality Division, General Permit GP-00-01, Table 1-2, http://www.deq.state.ok.us/WQDnew/stormwater/gp-00-01.pdf; Okl. Dep't of Envtl. Quality Water Quality Division, General Permit OKR 10, Table 1-1, http://www.deq.state.ok.us/wqdnew/stormwater/construction/okr10_final_permit_13_sep_2007.pdf

[124] Pennsylvania Dep't of Envtl. Protection, Comment and Response Document Erosion and Sediment Control and Stormwater Management for Oil and Gas Exploration, Production, Processing, Treatment Operations or Transmission Facilities (2008), *available at* http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-67458/05%20Comment%20and%20Response%2003%2028%2008.pdf.

[125] Governor's Marcellus Shale Advisory Commission § 7.2.1 (2011), *available at* http://www.mde.state.md.us/programs/Land/mining/marcellus/Documents/MSAC_Final_Report.pdf.

[126] West Virginia Dep't of Envtl. Protection, Industry Guidance, Gas Well Drilling/Completion, Large Water Volume Fracture Treatments (Jan. 8, 2010), *available at http://www.dep.wv.gov/oil-and-*gas/GI/Documents/Marcellus%20Guidance%201-8-10%20Final.pdf.

[127] Regulatory Compliance: Wyoming, http://www.google.com/url?sa=t&rct=j&q=regulatory%20compliance%3A%20wyoming%20coalbed%20methane%20temporarily%20discharging&source=web&cd=1&ved=0CB4QFjAA&url=http%3A%2F%2Fcbnga.com%2Fwp-content%2Fplugins%2Fdownload-monitor%2Fdownload.php%3Fid%3D8&ei=62mhTuXyLM3ViALS8_CDAQ&usg=AFQjCNHMcAeO3CkVEnTPy4TveCMud2Oxsg&cad=rja (summary for coalbed methane, but many regulations described apply to all oil and gas development).

4.3 Locating the Well Pad, Well, Pits, and Disposal Sites

When an oil or gas operator proposes to construct an access road and well pad, he or she must locate the well pad and/or the drilled well in accordance with state regulations. Most states regulate the spacing of wells—requiring well setbacks from property lines and/or other oil and gas wells, or minimum acreages per well, in order to prevent waste of subsurface oil and gas reserves and ensure efficient development.[128] For environmental and health purposes, however, some states also control the location of well pads, drilled wells, and/or on-site waste pits in order to prevent the contamination of nearby resources. These controls typically require that the well pad, well head, surface pits, or certain methods of drilling and fracturing waste disposal (land application sites, for example), be set back a minimum distance from a protected resource, such as a private water well, a public water supply, a stream, or a state park. They help to ensure that if a spill accidentally occurs during drilling or fracturing, for example, it will not contaminate water or other important natural resources. Several of these spills have occurred and in some cases have affected resources. In Pennsylvania, for example, a well "blew out"[129] during a fracturing operation, meaning that pressure forced the wellhead off the top of the well. This caused several thousands of gallons of fracturing fluid to enter a nearby creek and led the State of Maryland to threaten a lawsuit to address contamination.[130] Another Pennsylvania blow-out "discharged 35,000 gallons of HF [hydraulic fracturing] fluid into a state forest."[131] Further, an

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[128] *See* Ground Water Protection Council, *supra* note 31, at 14 (explaining that "[t]hroughout the period 1946 to 1960, most oil and gas producing states established a regulatory agency to enforce oil and gas conservation practices"). *But see id*. at 17 (noting that states also now regulate environmental aspects of oil and gas development and asserting that "[a]lthough current state oil and gas regulatory programs for water and environmental resource protection vary in scope and specificity, they invariably have the common elements necessary to ensure the development of oil and natural gas resources is accomplished in a manner designed to protect water resources").

[129] A "blowout" during fracturing is not technically a blowout, but the media typically has used this term. *See infra* notes **Error! Bookmark not defined.**-167 and accompanying text.

[130] Edward McAllister, *Chesapeake Stems Flow From Blown Pennsylvania Gas Well*, Reuters, Apr. 22, 2011, *available at* http://www.reuters.com/article/2011/04/22/us-chesapeake-blowout-idUSTRE73K5OH20110422; Office of the Att'y General, Attorney General Gansler Notifies Chesapeake Energy of the State's Intent to Sue for Endangering the Health of Citizens and the Environment, May 2, 2011, http://www.oag.state.md.us/Press/2011/050211.html.

[131] Dianne Rahm, Regulating Hydraulic Fracturing in Shale Gas Plays: The Case of Texas, 39 ENERGY POLICY 2974, 2976 (2011).

operator in Pennsylvania spilled a total of approximately 8,400 gallons of a lubricant gel for fracturing, some of which leaked into a nearby creek and wetland.[132] The State Review of Oil and Natural Gas Regulations—a private group tasked with reviewing state regulations and suggesting improvements—recognizes the importance of measures to avoid these types of incidents, which can pollute water and other resources, noting that "[w]here necessary . . . states should have standards to prevent the contamination of groundwater and surface water from hydraulic fracturing."[133]

There are several ways to prevent spills and other accidents from causing contamination of nearby resources. First, as many states do, the basic distance between the well or wellhead and natural resources can be regulated. Better still, states can identify the activities on the well pad that pose the highest risk, such as storing waste in an open pit in an area with high levels of precipitation (thus risking pit overflow). They can then ensure that those activities do not occur within a certain distance of important resources. To best mitigate risks, a state can require that the entire wellpad and all of the activities on the pad are set back minimum distances from important resources. New York has proposed this latter, most protective approach for natural resources, indicating that it will require the entire well pad to have a minimum set back from resources such as streams and wetlands.[134] These setbacks appear to be substantially more protective than those in all other states. As Reuters notes, New York's proposed buffers are "as much as 20 times larger than neighboring . . . Pennsylvania."[135] Several states take the middle ground—identifying certain potentially risky activities on the wellpad that should be set back

[132] *See* Laura Legere, DEP Orders Driller to Stop All Hydraulic Fracturing in Susquehanna County, The Times, Tribune, Sept. 26, 2009, *available at* http://thetimes-tribune.com/news/dep-orders-driller-to-stop-all-hydraulic-fracturing-in-susquehanna-county-1.283390#axzz1bX80FDUP.

[133] State Review of Oil and Natural Gas Environmental Regulations, Memorandum from The STRONGER Board to Persons Interested in Hydraulic Fracturing Guidelines, Update on the Development of Hydraulic Fracturing Guidelines, Feb. 8, 2010, *available at* http://www.strongerinc.org/documents/HF%20Guideline%20Web%20posting.pdf.

[134] *See infra* Table 3.

[135] Edward McAllister, *NY Gas Drillers' Victory Soured by Tough New Rules*, REUTERS, Oct. 21, 2011, *available at* http://www.reuters.com/article/2011/10/21/us-newyork-fracking-idUSTRE79K4XM20111021?feedType=RSS&feedName=topNews&rpc=76.

from water or other resources. Arkansas, for example, provides: "Mud, Circulation, and Reserve Pits constructed within the 100 year flood plain must be in accordance with any county or other local ordinance or requirement pertaining to the 100-year flood plain."[136] Oklahoma provides minimum required distances between land application of wastes such as produced water and certain water wells, streams, and wetlands.[137] New Mexico similarly prohibits temporary pits and below-grade tanks within 100-year flood plains.[138] New Mexico has some of the most detailed regulations that address minimum distances between pits and various protected resources. For temporary pits, permanent pits, and, in some cases, for surface deposit of "material excavated from the pit's construction," New Mexico's "pit rule," as revised in 2008 (and currently under review[139]), specifies minimum setbacks from "continuously flowing watercourse[s]," wetlands, floodplains, residences and other structures, private water wells, subsurface mines, and unstable areas.[140] Texas has the least stringent protections in this area. It does not appear require any well or pit setbacks from natural resources.[141]

Several states have recently revised or are proposing to revise regulations that would require setbacks in order to protect various protected resources. In 2007, for example, Colorado established "Public Water System Protection" regulations, which create buffer zones around areas that are or could be public water supplies. Within the internal buffer zone nearest to the protected water system, oil and gas drilling and completion may not occur. Within the intermediate buffer zone, drilling and completion is allowed, but with restrictions, such as the requirement that operators use closed-loop drilling and fracturing systems, which store all drilling and fracturing wastes in steel tanks. A third, external buffer zone is also open for oil and

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[136] Rule B-17 (2011).
[137] *See infra* Table 3.
[138] 19.15.17.10 NMAC (2011).
[139] *See infra* notes 318-320 and accompanying text.
[140] 19.15.17.10 NMAC (2011).
[141] *See* 16 TEX. ADMIN. CODE § 3.8(d)(4) (2011) (providing pit requirements); 16 TEX. ADMIN. CODE § 3.37 (2011) (providing well spacing requirements but no setback requirements).

gas drilling, again with certain restrictions to protect the public water supply.[142] New York is similarly proposing detailed setbacks in its revised Supplemental Generic Environmental Impact Statement, including a prohibition on high-volume hydraulic fracturing within the New York City and Syracuse watersheds, a 4,000-foot buffer zone around the watersheds, and within 100-year floodplains;[143] a 2,000-foot setback of the well pad from public water supplies;[144] a 500-foot setback from water wells;[145] and site-specific review for well pads proposed within 150 feet "of a perennial or intermittent stream, storm drain, lake, or pond" [146] and 500 feet of a principal aquifer.[147]

States such as Texas, which have not required any minimum setbacks with the exception of a setback from homes, should consider implementing better protections to ensure that accidental spills do not enter surface water or groundwater (through direct contact or soil seepage, for example). States such as Kentucky, which appears to only provide setbacks from structures and to prohibit discharge from holding pits into water, could improve regulations by implementing measures that are more easily enforced and better protect against unlawful discharge. It is difficult for state officials to locate every illegal discharge. It is easier, however, for them to measure the distance between a well pad and a natural resource. This required setback also would help to prevent the illegal discharge, thus providing a more specific directive to operators regarding the best means of avoiding prohibited discharges. A general prohibition on illegal discharges is important, in other words, but additional regulatory measures may be needed. (Spill prevention plans, secondary containment structures under chemical transfer stations and surface pits, emergency response plans, and clean-up requirements, as discussed in more detail below, also are important means of avoiding contamination.)

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[142] Department of Natural Resources, Oil and Gas Conservation Commission, Practice and Procedure, 2 CCR 404-1, http://cogcc.state.co.us/ (follow "COGCC Amended Rules Redline" hyperlink).
[143] New York SGEIS at 1-17.
[144] New York SGEIS at 1-17.
[145] New York SGEIS at 22.
[146] New York SGEIS at 7-76.
[147] New York SGEIS at 1-18.

Table 3 provides examples of state and local setback regulations. In Table 3, the object in parentheses is the object that must be set back from a protected resource, such as the wellhead, the well pad, a pit, or a tank. Tables 3a to 3e show examples of minimum required distances between wells drilled, well sites, and/or storage pits and natural and domestic resources for the following:

- Private water wells
- Public water supplies
- Structures/dwellings
- Streams
- Wetlands

Table 3a. Examples of minimum required distances between wells drilled, well sites, and/or storage pits and natural and domestic resources: Private water well

AR	*Search did not locate statute, regulation, or policy addressing this issue.*
CO	*Search did not locate statute, regulation, or policy addressing this issue.*
KY	*Search did not locate statute, regulation, or policy addressing this issue.*
LA	*Search did not locate statute, regulation, or policy addressing this issue.*
MI	300 ft. (well, assoc. surface facilities) Mich. Admin. Code R. 324.502 (2011)
MD	1,000 ft. (well). Code Md. Reg. 26.19.01.09 (2011)
MT	*Search did not locate statute, regulation, or policy addressing this issue.*
NM	500 ft. (temp. pit or below-grade tank); 500 ft. (permanent pit). 19.15.17.10 NMAC (2011)
NY[148]	500 ft. (well pad). R SGEIS 7.1.11.1 (2011)
ND	*Search did not locate statute, regulation, or policy addressing this issue.*
OH	*Search did not locate statute, regulation, or policy addressing this issue.*
OK	No land application of produced w/in 300 ft. of actively-producing well or of drill cuttings/fluids, petroleum-based cuttings w/in 300 ft. of water well. OAC 165: 10-7-19; 10-7-26 (2011)
PA	200 ft. (well). 58 P.S. 601.205 (2011)
TX	*Appears to have no minimum distance; setback is for homes, not wells.*
WV	200 ft. (well). W. Va. Code 22-6-21 (2011)
WY	If "close proximity to water supplies," (pit) O&G Commission may require closed-loop system, pit lining, etc. WY ADC OIL GEN Ch. 4 s 1(u).

[148] DRBC refers to proposed regulations of the Delaware River Basin Commission, which will apply to shale gas development in New York.

Table 3b. Examples of minimum required distances between wells drilled, well sites, and/or storage pits and natural and domestic resources: Public water supply

AR	*Appears to have no setback requirement.*
CO	300 ft. [149] (oil and gas location, excluding pipelines, roads, gathering lines); drilling and fracturing with conditions in buffer zones beyond 300 ft. 2 CCR 404-1 Rule 603 (2011)
KY	*Appears to have no setback requirement.*
LA	If a pit is "likely" to contaminate groundwater aquifer or underground source of drinking water, plan for preventing contamination required. LAC 43:XIX.309 (2011)
MI	2,000 ft. type I public water supply, 800 ft. types II +III (well separators, storage tanks, treatment equip.)
MD	1,000 ft. (well). COMAR 26.19.01.09 (2011)
MT	*Appears to have no setback requirement.*
NM	No temp. pit or below-grade tank "within a defined municipal fresh water well field". 19.15.17.10 NMAC (2011)
NY [150]	NY: 2,000 ft. (well pad/surface disturbance. R SGEIS 7.1.11.1 (2011). DRBC: 500 ft. (pad site)
ND	*Appears to have no setback requirement.*
OH	*Appears to have no setback requirement.*
OK	No discharge of produced water w/in 300 ft. of "actively-producing well used for municipal purposes". OAC 165: 10-7-19; no land applic. of petroleum-based cuttings w/in 1/4 mile of municipal supply. OAC 165:10-7-26; no commercial soil farming w/in 3 miles of watershed of public water supply lake. OAC:10-9-2
PA	200 ft. (well). 58 P.S. 601.205 (2011)
TX	*Appears to have no setback requirement.*
WV	*Appears to have no setback requirement.*
WY	If "close proximity"(pit) O&G Commission may require closed-loop system, pit lining, etc. WY ADC OIL GEN Ch. 4 s 1(u) (2011)

[149] Some new drilling with limitations is permitted within 301 to 500 feet of a Classified Water Supply Segment.

[150] DRBC refers to proposed regulations of the Delaware River Basin Commission, which will apply to shale gas development in New York.

Table 3c. Examples of minimum required distances between wells drilled, well sites, and/or storage pits and natural and domestic resources: Structures/dwellings

AR	200 ft. for habitable dwelling, 300 ft. for public use bldgs. (tanks and tank batteries). AOGC Rule B-26
CO	150 ft. or one and one-half the derrick height, whichever greater, from building unit; 350 ft. in high-density areas (wellhead) COGCC Rule 603(a)(1) and (e)(2); 350 ft.. in high-density areas (setback for production tanks, pits from buildings); 500 ft. in high-density areas (setback of production tanks, pits from educational and other group facilities). 2 CCR 404-1 Rule 603 (2011)
KY	150 ft. (well) KRS 353.500 (2011)
LA	500 ft. (well) in urban areas, or 200 ft. w/ owner's written permission Louisiana Office of Conservation Order No. U-HS[151]
MI	300 ft. (well, assoc. surface facilities)
MD	1,000 ft. (min. required distance between well and school or "occupied dwelling"). COMAR 26.19.01.09 (2011)
MT	*Search did not locate statute, regulation, or policy addressing this issue.*
NM	300 ft. (temp. pit or below-grade tank); 1,000 ft. (permanent pit). 19.15.17.10 NM ADC (2011)
NY[11]	Access roads "as far as practicable" from residences Rev. R SGEIS 7.10.2
ND	152.40 meters N.D. Admin. Code 43-02-03-28 (2011)
OH	150 ft. (well or tank battery)
OK	*Search did not locate statute, regulation, or policy addressing this issue.*
PA	200 ft. (well). 58 P.S. § 601.205 (2011)
TX	200 ft. statewide; [152] Fort Worth & Arlington 600 ft. (wellbore); Colleyville & Weatherford 1,000 ft.
WV	*Search did not locate statute, regulation, or policy addressing this issue.*
WY	If "close proximity"(pit) O&G Commission may require closed-loop system, pit lining, etc. WY ADC OIL GEN Ch. 4 s 1(u)

[151] State of Louisiana Office of Conservation, Order No. U-HS, available at http://dnr.louisiana.gov/assets/OC/eng_div/20090806-U-HS.pdf.

[152] Tex. Local Govt. Code § 253.005(c) (2011).

Table 3d. Examples of minimum required distances between wells drilled, well sites, and/or storage pits and natural and domestic resources: Stream

AR	Closed-loop systems required if oil-based drilling fluids used and mud or circulation pit is w/in 100 ft. of stream. Rule B-17 (2011); 200 ft. for protected streams, 300 for others (tanks and tank batters) Rule B-26
CO	300 ft. if suitable for or intended to become potable (see buffer zone requirements) 2 CCR 404-1 Rule 603 (2011)
KY	Holding pits (for produced water) may not discharge pollutant into state waters, in violation of CWA or Kentucky water laws. 401B KAR 30:031 Section 4(1) (2011)[153]
LA	*Search did not locate statute, regulation, or policy addressing this issue.*
MI	*Search did not locate statute, regulation, or policy addressing this issue.*
MD	*Search did not locate statute, regulation, or policy addressing this issue.*
MT	*Search did not locate statute, regulation, or policy addressing this issue.*
NM	300 ft. (temp. or permanent pit or below-grade tank[154]). 19.15.17.10 NMAC (2011)
NY	NY: site-specific review w/in 150 ft. (well pad). Rev. SGEIS p. 3-15; NY 500 ft. (fueling tanks). R SGEIS 7.1.3.1. DRBC: 500 ft.[155] (pad site)
ND	No reserve pits "in, or hazardously near, bodies of water." NDCC 43-02-03-19 (2011)
OH	No pits w/in flooding zone
OK	No land application of produced water, drill fluids/cuttings, petroleum-based drill cuttings w/in 100 ft. of perennial stream, 50 ft. of intermittent stream. OAC 165: 10-7-17; 10-7-19; 10-7-26 (2011); no commercial soil farming w/in 100 ft. OAC 165:10-9-2 (2011)
PA	150 ft. (well site or well). 58 P.S. § 601.205 (2011)
TX	*Appears to have no setback requirement.*
WV	*Search did not locate statute, regulation, or policy addressing this issue.*
WY	*Search did not locate statute, regulation, or policy addressing this issue.*

[153] 401 Ky. Admin. Code Section 9(5)(a) (2011) provides, "Holding pits shall be constructed in accordance with KRS Chapter 151 and Division of Waste Management administrative regulation 401 KAR 30:030," which now appears to be codified as 401 KAR 30:031. 401 Ky. Admin. Code Section 1(13) (2011) defines "holding pit" as a pit that holds produced water.

[154] The regulations require the setback to be from a "continuously flowing watercourse." The setback is 200 feet for other "significant" watercourses.

[155] The regulations refer to "water body."

Table 3e. Examples of minimum required distances between wells drilled, well sites, and/or storage pits and natural and domestic resources: Wetland

AR	Above-ground pits or closed loop systems require in wetlands where water table is 10 ft. or fewer below surfaces. Rule B-17 (2011); 200 ft. (tanks/tank batteries). AOGC Rule B-26 (2010)
CO	"Operators shall avoid or minimize impacts to wetlands and riparian habitats to the degree practicable." COGCC Rule 1002; operations in wetlands shall "incorporate adequate measures and controls to prevent significant adverse environmental impacts. COGCC Rule 901; Definitions (2011)
KY	Holding pits (for produced water) may not be in wetlands[156] or discharge pollutant into state waters, including wetlands, in violation of CWA or Kentucky water laws. 401B KAR 30:031 Section 4(1) (2011) [157]
LA	Production equipment allowed in wetlands, but if cannot build dike for containment, must use impervious decking w/ curbs, gutters, and/or sumps La. Admin. Code 33:V.1121 (2011)
MI	*Search did not locate statute, regulation, or policy addressing this issue.*
MD	May deny permit if will threaten wetlands. COMAR 26.19.01.09 (2011). No drilling in Chesapeake Bay Critical Area unless written approval from Critical Area Commission. *Id*.
MT	*Search did not locate statute, regulation, or policy addressing this issue.*
NM	500 ft. (temp. or permanent pit or below-grade tank). NMAC 19.15.17.10 (2011)
NY[11]	NY: 500 ft. (fueling tanks). R SGEIS 7.1.3.1 (2011). DRBC: 500 ft. (pad site)
ND	*Search did not locate statute, regulation, or policy addressing this issue.*
OH	*Appears to have no setback requirement.*
OK	No land application of produced water, drill fluids/ cuttings petroleum-based drill cuttings w/in 100 ft. of wetland. OAC 165:10-7-17; 10-7-19 10-7-26 (2011); no commercial soil farming w/in 100 ft. OAC 165:10-9-2 (2011)
PA	100 ft. (wetlands > 1 acre). 58 P.S. § 601.205 (2011)
TX	*Appears to have no setback requirement.*
WV	*Appears to have no setback requirement.*
WY	*Search did not locate statute, regulation, or policy addressing this issue.*

[156] 401B Ky. Admin. Regs. § 30:031 Section 12 (2011). 401 Ky. Admin. Code Section 9(5)(a) (2011) provides, "Holding pits shall be constructed in accordance with KRS Chapter 151 and Division of Waste Management administrative regulation 401 KAR 30:030," which now appears to be codified as 401 KAR 30:031. 401 Ky. Admin. Code Section 1(13) (2011) defines "holding pit" as a pit that holds produced water.

[157] 401 Ky. Admin. Code Section 9(5)(a) (2011) provides, "Holding pits shall be constructed in accordance with KRS Chapter 151 and Division of Waste Management administrative regulation 401 KAR 30:030." 401 Ky. Admin. Code Section 1(13) (2011) defines "holding pit" as a pit that holds produced water.

4.4 Transporting Equipment to the Well Pad

During construction of an access road and well pad and subsequent production, oil and gas operators who drill and fracture shale wells must move heavy equipment over local roads—requiring anywhere between "320 and 1,365 truckloads of equipment to bring a well into production.[158] This, predictably, increases strain on the roads[159] and often requires road upgrades.[160] Although all oil and gas development increases traffic on roads, fracturing substantially raises the numbers and types of vehicles on roads. The National Park Service estimates, for example, that fracture stimulation fluids and materials for one site require somewhere between 100 and 1,000 truckloads (this likely differs substantially depending on whether water is piped or trucked to the site), while "fracture stimulation equipment (pumps, trucks, tanks)" requires 100 to 150 truckloads.[161]

To accommodate the rise of heavy traffic on roads, local officials and operators sometimes require operators to post a bond.[162] In the Barnett Shale, the City of Denton has gone further, requiring operators to "enter into a road repair or road maintenance agreement" with the city. Other municipalities have implemented similar requirements.[163] The agreements, in addition to including bonding requirements, often designate which routes operators may use, how they must repair damage, and the damage for which the city will not be liable, among other provisions.

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[158] Nat'l Park Service, Potential Development of the Natural Gas Resources in the Marcellus Shale 8 (Dec. 2008), *available at* http://www.eesi.psu.edu/news_events/EarthTalks/2009Spring/materials2009spr/NatParkService-GRD-M-Shale_12-11-2008_view.pdf.

[159] *See, e.g.*, Michele Rogers, Penn State College of Agricultural Sciences, Marcellus Shale: What Local Government Officials Need to Know 11 (2008)("The process of drilling, fracturing, and maintaining natural gas wells can create significant heavy truck traffic on rural roads, many of which were not designed for carrying vehicles of this size.").

[160] Nat'l Park Service, *supra* note 158, at 8 ("Many rural roads near park areas overlying and near the Marcellus Shale occurrence will not meet standards necessary for large trucks that will be used to haul equipment, water, and other supplies to and from drill pad sites. These roads will need to be upgraded through widening, and surfacing; and road curve angles may need to be reduced.").

[161] Nat'l Park Service, *supra* note 158, at 9.

[162] *See* Rogers, *supra* note 159.

[163] Martin E. Garza, *Local Regulation of Gas Development in an Urban Setting: The Texas Experience*, *in* OIL AND GAS LAW 273, 285 (The Center for American and International Law, eds., Sept. 2008).

Some cities in the Barnett Shale also have charged operators road remediation assessments to cover the cost of repair.[164] Municipalities responding to heavier traffic and road expansion needs should look to these plans as potential methods of successfully contracting with operators.

[164] *Id*. at 286-87.

4.5 Drilling and Casing a Well; Preventing Blowouts

Some of the most detailed state regulations apply to the process of drilling and casing a well once an oil or gas operator has received permission to use or expand local roads and has prepared an access road and well site. States regulate the metal liner ("casing") that is cemented into a well to prevent wells from collapsing, underground water from mixing with gas and oil in the well, and oil and gas from migrating out of the well into water, basements, soils, and other underground resources.[165] They also require certain measures to prevent blowouts during drilling and fracturing. A blowout, as briefly introduced above, is "an uncontrolled intrusion of fluid under high pressure into the wellbore, from the rock formation,"[166] and it can have both subsurface and surface effects. Informally, when the wellhead blows off a well during the fracturing process, media accounts also describe this as a "blowout."[167] States typically regulate the required depth of surface casing—the string of casing that protects underground water—as well as the strength of the casing, the strength of the cement that holds the casing, the method of cementing in the casing, and the length of time for which the cement that holds the casing must remain undisturbed. Some states also require operators to prepare a cement and/or casing log that describes the materials and methods used.

The regulation of casing, cementing, and blowout equipment is necessary for the protection of underground water supplies—a concern often addressed in the popular media, as discussed by Professor Matt Eastin. Proper casing, secured by adequate cement, ensures that the substances in the wellbore, including gas and fracturing fluid (during the fracturing stage), do not mix with other underground substances, including water. As the State Review of Oil and Natural Gas

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[165] Ground Water Protection Council, *supra* note 31, at 21 (describing the role of casing in protecting groundwater); *cf.* East Resources, Inc., DelCiotto No. 2, Subsurface Natural Gas Release Report Roaring Branch, McNett Township, Lycoming County, Pennsylvania 10-11 (Sept. 18, 2009) (in a well in McNett Township that appeared not to have been fractured, noting a gas release that "resulted in sediment and gas migration into streams, groundwater wells, springs, culverts, and a residential structure" partially as a result of a flaw in the casing).

[166] NY Revised SGEIS, *supra* note xx, at 10-3, n. 4.

[167] *See id*. (explaining that this is not technically a blowout but is described as one).

Environmental Regulations observes, "The setting of surface casing to an appropriate depth is critical for meeting anticipated pressures and for protecting fresh water aquifers."[168]

The Ground Water Protection Council, an association of state regulators,[169] conducted a survey of state regulators that found no "proven" incident of underground water pollution from coalbed methane.[170] Academics and nonprofit groups have since extensively debated this conclusion. In Dimock, Pennsylvania, for example, methane may have migrated to oil and gas wells as a result of fracturing, and a recent paper suggests that fracturing may be linked to methane contamination of water wells.[171] Although ongoing scientific analysis will be necessary to identify the source of gas and other substances in groundwater, the literature and incidents that have occurred in Pennsylvania suggest that drilling and improper casing of wells are in some cases associated with methane migration into groundwater, surface water, soil, and structures.[172] All hydraulically

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[168] State Review of Oil & Natural Gas Envtl. Regulations, Colorado Hydraulic Fracturing State Review 6, Oct. 2011, *available at* http://www.strongerinc.org/documents/Colorado%20HF%20Review%202011.pdf.

[169] The GWPC is a 501(c)6) organization founded to "promote and ensure the use of best management practices and fair but effective laws regarding comprehensive ground water protection." Ground Water Protection Council, Our Mission, http://www.gwpc.org/about_us/about_us.htm.

[170] Ground Water Protection Council, Survey Results on Inventory and Extent of Hydraulic Fracturing in Coalbed Methane Wells in the Producing States 3 (Dec. 15, 1998), *available at* http://www.gwpc.org/e-library/elibrary_documents/e-library_documents_general/Hydraulic%20fracturing%20methane%20coal%20beds.pdf .

[171] S.G. Osborne et al., *Methane Contamination of Drinking Water Accompanying Gas-Well Drilling and Hydraulic Fracturing*, 108 PROCEEDINGS OF THE NAT'L ACADEMY OF SCIENCES 8172, *available at* http://www.pnas.org/content/108/20/8172.full.pdf+html.

[172] *See* East Resources, Inc., *supra* note 165 (concluding that both naturally-occurring stray gas and gas from a well with casing flaws drilling in McNett Township entered groundwater and a structure); Penn. Dep't of Envtl. Protection, Draft, Stray Gas Migration Associated with Oil and Gas Wells, Oct. 28, 2009, *available at* http://www.dep.state.pa.us/dep/subject/advcoun/oil_gas/2009/Stray%20Gas%20Migration%20Cases.pdf (concluding that for this same well: "A natural gas leak from an East Resources Oriskany well was confirmed on July 27, 2009. Methane gas from the well impacted multiple private drinking water wells and two tributaries to Lycoming Creek, forced one resident to evacuate her home, and required the closure of access roads near the well. Company personnel took necessary measures to stop the gas leak at the well and stream and drinking water well conditions improved. The suspected cause of the leak is a casing failure of some sort."); *id*. at 4 (after locating combustible gas in a residential basement, concluding that "two recently drilled gas wells were over-pressured and were producing from different geologic strata. Isotopic analysis indicated that a specific gas well was the probable source of the fugitive gas"); *id*.at 5-6 ("The discovery of fugitive gas in the soil near the residences [homes near Walnut Creek in Erie County], forced the Erie County Health Dept. to evacuate the neighborhood. The residents were displaced for at least two months. Through the use of isotopic analysis and through investigation performed by the Department's field staff, it was determined that the recently drilled neighboring gas wells were the cause of the migration."); Commonwealth of Pennsylvania, Dept. of Envtl. Protection, Inspection Report, Inspection Record #

fractured wells must of course be drilled before they are fractured, and it is imperative that states ensure that wells are properly cased to protect groundwater in the short term. Proper casing, combined with adequate plugging, also is imperative to ensure long-term well integrity and to avoid the leaking of methane from old wells, as has occurred in Pennsylvania.[173]

Casing, cementing, and blowout protections vary widely among states, and most were written before the recent expansion of fracturing activity.[174] Kentucky's and West Virginia's casing depth requirements appear to be the least stringent, at 30 feet. Other states, such as Texas and Montana, have generalized mandates that casing adequately protect fresh water (thus not specifying a depth below groundwater), but officials in these states may require specific depths in each well permit. Colorado similarly determines casing depth on a well-by-well basis. The

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1565790, Permit 37-031-24332, Sept. 21, 2006 ("Inspection resulted in finding that gas is leaking around seven inch casing"). *Cf*. Commonwealth of Pennsylvania, Dept. of Envtl. Protection, In The Matter of : David C. and Linda J. Osterberg, Order, Sept. 28, 2010, at 3 (concluding that isotopic analysis of gas from a private drinking water well and free gas from the production tubing of a well with compromised casing showed that the gas was "similar in origin" and that the well was a "possible source and/or contributing source of the combustible free gas" in the water supply); Commonwealth of Pennsylvania, Dept. of Envtl. Protection, In the Matter of: Schreiner Oil and Gas, Inc., Order, Feb. 23, 2010, at 5 (describing a DEP determination that drilling activities "were responsible for the pollution" of a water supply with combustible gas); Letter from Penn. Dep't of Envtl. Protection, Knox District Office to Mr. Kevin Wedekind, Jan. 15, 2010 (indicating that the Department "has determined that the drilling, alteration, or operation activities at . . . [an EQT Production Company well] diminished" a resident's water supply); Letter from Penn. Dept. of Envtl. Protection to Mrs. Joy Rapp, Nov. 3, 2009 (noting that the Department "determined that . . . the drilling, alteration, or operation of oil or gas wells affected" the resident's water supply but that the operator had installed treatment for the water); Letter from Penn. Dept. of Envtl. Protection, Knox District Office to Mr. James Baldwin, Jan. 27, 2009 (concluding that the resident's water supply "had been affected" by a gas well site "based on information gathered from site inspections, documented timelines, gas and water well records, area geology, and our sample results"); Letter from Pennsylvania Dep't of Envtl. Protection, Northwest Regional Office, to Mr. Brent Vath, May 22, 2009 (concluding, based on "laboratory results" of a "water sample," that an operator affected the resident's water well "by gas activity"). Note that the information available for the wells described in this footnote does not indicate whether the wells were fractured. This information should not be interpreted to mean that fractured wells have leaked gas or other pollutants.

[173] Penn. Dep't of Envtl. Protection, Stray Gas Migration, *supra* note 172 (noting that after gas contamination of a water well in a basement was discovered, plugging of an abandoned gas well and removing the pavement over the well improved conditions); *id*. at 12 (noting that "[o]rigin/mechanism of [gas] migration ["inside a private water supply well"] is an abandoned gas well")

[174] Some states, such as Montana and Pennsylvania, have recently updated their casing requirements, however. *See* 36.22.1106 (unofficial final rules), http://bogc.dnrc.mt.gov/PDF/FinalFracRules.pdf; Proposed Rulemaking, Environmental Quality Board, 40 Pa.B. 3845, July 10, 2010, http://www.pabulletin.com/secure/data/vol40/40-28/1248.html; regulations codified at 25 Pa. Code § 78.83 et seq. (2011).

State Review of Oil and Natural Gas Environmental Regulations recommends that Colorado "review how available information is used to determine minimum surface casing depths and how these depths assure that casing and cementing procedures are adequate to protect fresh groundwaters."[175] Other states that do not have minimum surface casing depths should also follow this recommendation.

With respect to the strength of casing materials, an initial survey suggests that only New York, North Dakota, and Pennsylvania require that used casing be pressure tested prior to being installed in a well. States that do not have this provision should consider implementing it. Cementing strength requirements are similar across states but differ in terms of the amount of time that the cement must set and the pressure in (typically measured in pounds per square inch) that the cement must withstand. States should review these differences and determine whether they are merited by differing geologic conditions. Finally, as shown in Table 4e, many states require operators to submit a bond and casing log or to submit a log in certain circumstances. In Oklahoma, for example, if an agency inspector "does not witness cementing, and in other instances based on site-specific circumstances, a cement bond log can be required."[176] To better reduce risks of inadequate casing and long-term well integrity, states should consider requiring an agency staff member familiar with casing requirements to be present at the site when well casing should occur; this could help to prevent casing problems before they occur. Additionally, to identify casing problems quickly and to ensure that repairs occur where needed, states should require operators to prepare and submit comprehensive casing and cement logs, regardless of site

[175] State Review of Oil & Natural Gas Envtl. Regulations, Colorado Hydraulic Fracturing State Review 6, Oct. 2011, *available at* http://www.strongerinc.org/documents/Colorado%20HF%20Review%202011.pdf.

[176] State Review of Oil & Natural Gas Envtl. Regulations, Oklahoma Hydraulic Fracturing State Review 11, Jan. 2011, *available at* http://www.strongerinc.org/documents/Final%20Report%20of%20OK%20HF%20Review%201-19-2011.pdf.

circumstances, that show the depth, type, amount, and strength of casing and cement installed in each well.[177]

In addition to ensuring that casing and cementing will adequately protect underground water sources during the drilling and fracturing process, states must prevent well blowouts during drilling and fracturing. Some states, even prior to the shale gas fracturing boom, already had detailed blowout prevention regulations, with Montana providing one of the most comprehensive controls. Montana mandates, for example, minimum specifications for "drilling spools for blowout preventer stacks," specific blowout equipment for "wells in areas of abnormal or unknown formation pressures," installation of blowout prevention and well control equipment for "development wells and in all areas of known formation pressures," and additional protections, such as remote blowout prevention controls.[178] Colorado, Louisiana, Michigan, and Oklahoma have similarly detailed blowout requirements, as summarized in Table 4. Other states, with weaker protections in this area, have only general blowout prevention requirements. Arkansas, for example, provides, "All proper and necessary precautions shall be taken for keeping the well under control during drilling operations, including but not limited to the use of blow-out preventers . . . ." The state also requires that blow-out preventers "be tested at regular intervals to insure proper operation."[179] States with generalized blowout prevention requirements should consider the specific requirements in states such as Montana and Oklahoma, including specific types of rams,[180] remote blowout prevention controls, and other protective measures.

Some states, including New York, Pennsylvania, Montana, and North Dakota, have recently updated or proposed to update their casing, cementing, and blowout regulations to recognize potential fracturing risks. These regulations recognize that fracturing can increase pressure on the

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[177] Both of these proposals of course require adequate funding and staff with expertise, which will strain thin state budgets. The accompanying white paper "State Enforcement of Shale Gas Regulations" suggests creative ways to increase funding, such as Pennsylvania's raising the permit fee paid by each operator applying for a permit to drill.

[178] Montana Admin. Rule 36.22.1014 (2011).

[179] Arkansas Oil and Gas Commission General Rules and Regulations, Rule B-16 (2011).

[180] These include "blind rams" that lock together no matter the activity occurring in the well, for example.

well and potentially compromise casing, thus requiring more protective measures. States that have not updated their casing requirement despite enhanced fracturing activities should follow these states' lead. Montana's revised 2011 rules provide, for example, among other requirements, "If the operator proposes hydraulic fracturing through production casing or through intermediate casing, the casing must be tested to the maximum anticipated treating pressure. If the casing fails the pressure test it must be repaired or the operator must use a temporary casing string (fracturing string)."[181] Pennsylvania, in turn, revised its rules in 2010 to require operators to "prepare and maintain a casing and cementing plan showing how the well will be drilled and completed."[182] It also added intermediate casing requirements, providing that "[i]f the well is to be equipped with an intermediate casing, the casing shall be cemented from the casing seat to a point at least 500 feet above the seat." Further, Pennsylvania revised its regulations to require testing of used casing, pressure testing of all casing, welding of cases with "at least three passes," and a cement and bond log.[183] For blowout prevention, the state required casing attached to "a blow-out preventer with a pressure rating of greater than 3,000 psi" to be pressure tested. It also specified the "passing pressure test" and required operators to use blow-out preventers "[w]hen drilling a well that is intended to produce natural gas from the Marcellus Shale formation."[184] North Dakota, in turn, has proposed to add a new section to its oil and gas regulations entitled "Hydraulic Fracture Stimulation." This section would require, *inter alia*, that the "frac string" must reach a minimum depth below the top of the cement of a certain formation, "whichever is

[181] 36.22.1106 (unofficial final rules), http://bogc.dnrc.mt.gov/PDF/FinalFracRules.pdf.

[182] Proposed Rulemaking, Environmental Quality Board, 40 Pa.B. 3845, July 10, 2010, http://www.pabulletin.com/secure/data/vol40/40-28/1248.html; regulations codified at 25 Pa. Code § 78.83 et seq. (2011).

[183] *See id*. *See also* State Review of Oil & Natural Gas Envtl. Regulations, Pennsylvania Hydraulic Fracturing State Review 7, Sept. 2010, *available at* http://www.strongerinc.org/documents/PA%20HF%20Review%20Print%20Version.pdf.

[184] Proposed Rulemaking, *supra* note 182, codified at 25 Pa. Code § 78.72 (2011) (noting that the updated regulations require "that a cement job log, that documents the actual procedures and specifications of the cementing, be maintained by the operator).

deeper," that the annulus (space) between the intermediate casing and frac string "be pressurized and monitored during frac operations," and that certain pressure relief valves be used.[185]

Tables 4a to 4f provide examples of casing, cementing, and blowout prevention requirements for the following:

- Depth of surface casing below lowest fresh groundwater
- Strength of surface (and other) casing
- Restrictions on reuse of surface casing
- Cementing
- Log
- Blowout prevention

[185] N.D. Admin. Code § 43-02-03-27.1 (2011) (proposed 2011), *available at* https://www.dmr.nd.gov/oilgas/rules2012changes.pdf.

Table 4a. Regulation of the well drilling process: casing, cementing, and blowout prevention: Depth of surface casing below lowest fresh groundwater

AR	"Surface casing shall be set and cemented at least . . . 100 feet below the deepest encountered freshwater zone." AOGC Rule B-19(e) (2011). All Fayetteville Shale fields:[186] min. 500 ft. of surface casing.[187]
CO	50 ft. Casing must be set "in a manner sufficient to protect all fresh water and to ensure against blowouts or uncontrolled flows; individual casing program adopted for each well. 2 C CR 404-1 Rule 317(g) (2011)
KY	30 ft. (surface, intermed., or long string). 805 KAR 1:020 Section 3:1 (2011)
LA	Casing lengths and strengths differ depending on "total depth of contact"; standard lengths and strengths only apply "where no danger of pollution of fresh water sources exists." 43 LA ADC Pt XIX, § 109 (2011). Below 9,000 feet, more than 1,800 ft. of casing requ. and test pressure at least 1000 lbs. per sq. in. Id.
MD	100 ft. or deepest known workable coal, whichever deeper. COMAR 26.19.01.10 (o)(4)
MI	100 ft. below all fresh water strata. MICH. ADMIN. CODE R 324.408 (2011)
MT	"Sufficient surface casing must be run to reach a depth below all fresh water located at levels reasonably accessible for agricultural and domestic use." MONT. ADMIN. R. 36.22.1001 (2011)
NM	"[A]s may be necessary to effectively seal off and isolate all water-, oil- and gas-bearing strata." NM ADC 19.15.16 (2011)
NY	75 ft. or into bedrock, whichever deeper (100 ft. primary and principal aquifers). R SGEIS 7.1.4.2, id. at 7.3 (2011)
ND	"[A]t sufficient depths to adequately protect and isolate all formations containing water, oil, or gas or any combination of these." NDAC 43-02-03-21 (2011)
OH	50 feet.;[188] no agency specific review if at least 500 ft. between highest perforated portion of casing and lowest groundwater. ORC 1509.17(D) (2011)
OK	50 ft. or 90 ft. below surface, whichever deeper. OAC 165:10-3-4
PA	50 ft. or into consolidated rock, whichever deeper; if encounters additional freshwater, centralizers required. 25 Pa. ADC 78.83 (2011)

[186] See Arkansas Oil and Gas Commission, Order No. 146-2005-09, Cove Creek Field, Sept. 27, 2005, http://www.aogc.state.ar.us/Field%20Rules/Fayetteville%20Shale/146-2005-09.pdf; Arkansas Oil and Gas Commission, Griffin Mountain Field, Amendment, July 26, 2005, http://www.aogc.state.ar.us/Field%20Rules/Fayetteville%20Shale/114-2005-07.pdf; Arkansas Oil and Gas Commission, Gravel Hill Field, Order No. 97-2005-06, http://www.aogc.state.ar.us/Field%20Rules/Fayetteville%20Shale/97-2005-06.pdf; Arkansas Oil and Gas Commission, Scotland Field, Order No. 96-2005-06, June 28, 2006, http://www.aogc.state.ar.us/Field%20Rules/Fayetteville%20Shale/96-2005-06.pdf.

[187] *See also* "All fresh water sands shall be fully protected by the setting and cementing of surface casing to prevent the fresh water sands from becoming contaminated with oil, gas, or salt water." A.O.G.C. Rule B-15 (2010).

[188] STRONGER, Ohio Hydraulic Fracturing State Review (Jan. 2011), *available at* http://www.dnr.state.oh.us/Portals/11/oil/pdf/stronger_review11.pdf.

TX	"[S]et and cement sufficient surface casing to protect all usable-quality water strata." 16 TAC § 3.13 (2010)
WV	"(30) feet below the deepest fresh water horizon (that being the deepest horizon that will replenish itself and from which fresh water or usable water for household, domestic, industrial, agricultural, or public use may be economically and feasibly recovered)" W. Va. CSR § 35-4-11.3 (2011)
WY	"[B]elow all known or reasonably estimated utilizable groundwater." WCWR 055-000-003 Section 22(a)

Table 4b. Regulation of the well drilling process: casing, cementing, and blowout prevention: Strength of surface (and other) casing

AR	Steel alloy of "sufficient internal yield pressure to withstand the anticipated maximum pressures to which the casing will be subjected in the well." AOGC Rule B-19 (d) (2010). Production casing must "be sufficient to contain the max. anticipated" fracturing which "shall not exceed 80% of minimum internal yield pressure for casing. *Id*.
CO	"[P]rotect any potential oil or gas bearing horizons penetrated during drilling from infiltration of injurious waters from other sources, and to prevent the migration of oil, gas or water from one (1) horizon to another, that may result in the degradation of ground water." COGCC Rule 317 (2011)
KY	*Search did not locate statute, regulation, or policy addressing this issue.*
LA	Casing lengths and strengths differ depending on "total depth of contact"; standard lengths and strengths only apply "where no danger of pollution of fresh water sources exists." 43 LA ADC Pt XIX, § 109 (2011). Below 9,000 feet, more than 1,800 ft. of casing required, and test pressure must be at least 1,000 lbs. per sq. in. *Id*.
MD	*Search did not locate statute, regulation, or policy addressing this issue.*
MI	"Of sufficient weight, grade, and condition to have a designed minimum internal yield of 1.2 times the greatest expected well bore pressure to be encountered". MICH. ADMIN. CODE R 324.410 (2011)
MT	"Suitable and safe." MT ADC 36.22.1001 (2011)
NM	*Search did not locate statute, regulation, or policy addressing this issue.*
NY	Surface casing: mill test of at least 1,000 psi. R SGEIS 7.1.4.2 (2011)
ND	Surface casing: "new or reconditioned pipe that has been previously tested to one thousand pounds per square inch [6900 kilopascals]." ND ADC 43-02-03-21 (2011)
OH	"Steel production casing." ORC 1509.17 (2011)
OK	"[O]il field grade steel casing." OAC 165:10-3-4
PA	Internal pressure rating "20% greater than anticipated maximum pressure." 25 PA ADC 78.84 (2011)
TX	"[S]teel casing that has been hydrostatically pressure tested with an applied pressure at least equal to the maximum pressure to which the pipe will be subjected in the well"; mill test for new casing. 16 TAC 3.13 (2010). "Good and sufficient wrought iron or steel casing." Tex. Nat. Res. Code 91.011 (2010)
WV	No casing strength requirement.
WY	*Search did not locate statute, regulation, or policy addressing this issue.*

Table 4c. Regulation of the well drilling process: Casing, cementing, and blowout prevention: Restrictions on reuse of surface casing

AR	All Fayetteville fields: "new or second-hand" production casing allowed.
CO	*Search did not locate statute, regulation, or policy addressing this issue.*
KY	*Search did not locate statute, regulation, or policy addressing this issue.*
LA	*Search did not locate statute, regulation, or policy addressing this issue.*
MD	*Search did not locate statute, regulation, or policy addressing this issue.*
MI	*Search did not locate statute, regulation, or policy addressing this issue.*
MT	*Search did not locate statute, regulation, or policy addressing this issue.*
NM	*Search did not locate statute, regulation, or policy addressing this issue.*
NY	Pipe must be new, unless used casing is pressure tested before drilling. R SGEIS 7.1.4.2 (2011)
ND	"N]ew or reconditioned pipe that has been previously tested to one thousand pounds per square inch [6900 kilopascals]. ND ADC 43-02-03-21 (2011)
OH	"Good and sufficient wrought iron or steel casing." ORC 1509.17 (2011)
OK	"[S]urface casing shall be oil field grade steel casing." OK ADC 165:10-3-4 (c)(7)(D) (2011)
PA	Used surface, intermed., or production casing must withstand "the anticipated maximum pressure to which it will be exposed for 30 minutes with not more than a 10% decrease in pressure." 25 PA ADC 78.84(c) (2011)
TX	All used casing must be "[s]teel casing that has been hydrostatically pressure tested with an applied pressure at least equal to the maximum pressure to which the pipe will be subjected in the well." 16 TAC § 3.16(b) (2011)
WV	*Search did not locate statute, regulation, or policy addressing this issue.*
WY	*Search did not locate statute, regulation, or policy addressing this issue.*

Table 4d. Regulation of the well drilling process: Casing, cementing, and blowout prevention: Cementing

AR	If "setting and cementing of production and/or any intermediate casing" as planned in cement program does not occur to isolate hydraulic fracturing zone, Dept. may require correction of cement deficiencies before fracturing initiated. AOGC Rule B-19(f) (2010)
CO	Surface, intermediate, and production casing cement 300 psi after 23 hrs., 800 psi after 72 hrs. at 95 deg. F. 2 CCR 404-1 Rule 317 (2011); COGCC Rule 317(h)
KY	Protective casing cemented to surface or 30 "feet into the next larger string of cemented cases" 805 KAR 1:020. "Sufficient cement" required where abnormal pressures expected. 805 KAR 1:020 Section 3 (2011)
LA	Must "fill annular space to a point 500 feet above the shoe," if drop of 10% of test pressure after 30 minutes, must ensure cementing will hold test pressure for at least 30 minutes w/out more than 10% drop. LAC 43:XIX.109 (2011)
MD	Surface casing cement: API Class A, not > 3% calcium chloride, no other additives, must be "[a]llowed to set at static balance or under pressure for a minimum of 12 hours before drilling the plug." COMAR 26.19.01.10(P) (2011)
MI	Well casing cement must set "until the tail-in slurry reaches 500 psi compressive strength, but for not less than 12 hours"; cement "of a composition and volume approved by the supervisor". MICH. ADMIN. CODE R 324.411 (2011)
MT	Surface casing cement must set until it "has reached a compressive strength of 300 [psi]," no testing until set at least 8 hrs. MONT. ADMIN. R. 36.22.1001 (2011)
NM	By pump and plug unless otherwise authorized. Must fill "annular space behind casing to the top of the hole." May sometimes use oil-based casing packing material in lieu of hard-setting cement. In certain counties, must set until min. compressive strength 500 psi. NM ADC 19.16.16 (2011)
NY	Surface casing cement by pump and plug and circulated to surface, minimum 25% excess cement pumped, cement slurry to mfr. or contractor specifications, no casing disturbance until achieves compressive strength 500 psi., API Spec. 10A, wait 8 hrs. before disturbing. R SGEIS 7.1.4.2
ND	Surface casing by pump and plug, fill annular space behind casing to bottom of cellar or to surface of ground; must stand under pressure at least 12 hrs. Surface casing strings must stand under pressure 5 hrs. until reach compressive strength of at least 500 psi. All filler cements must reach 200 psi compressive strengths w/in 24 hrs. ND ADC 43-02-03-21 (2011). Addtl. cementing and pressure tests proposed for fractured wells. ND Admin. Code 43-02-03-27.1 (proposed 2011)[189]
OH	*Search did not locate statute, regulation, or policy addressing this issue.*
OK	Tubing and plug, pump and plug, or displacement, set at least 8 hrs. before drilling. If not circulated to surface, shall determine top of cement. OK ADC 165:10-3-4 (c)(7)(D) (2011)
PA	Surface casing cement must be "cement that meets or exceeds the ASTM International C 150, Type I, II or III Standard or API Specification 10". 25 PA ADC 78.85 (2011)
TX	Surface casing strings must stand until compressive strength of at least 500 psi in zone of critical cement; cement in this critical zone "shall have a 72-hour compressive strength of at least 1,200 psi." 16 TAC 3.13 (2010)

[189] For proposed rules, see https://www.dmr.nd.gov/oilgas/rules2012changes.pdf.

WV Cement for annular space API Class A, not > 3% calcium chloride, no other additives, withstand min. 500 psi, set 8 hrs. W. Va. CSR 35-4-11 (2011).

WY "[C]emented casing string shall stand under pressure until cement at the shoe has reached a compressive strength" of 500 psi; all cements minimum compressive strength of 100 psi in 24 hours at 80 deg. F. WY ADC GEN Ch. 3 s 22(a)(ii) (2011)

Table 4e. Regulation of the well drilling process: Casing, cementing, and blowout prevention: Log

AR	Bond log "or other cement evaluation tool" may be required if "setting and cementing of production and/or any intermediate casing" as planned in cement program does not occur to isolate hydraulic fracturing zone. A.O.G.C. Rule B-19(f) (2010)
CO	Copies of "all logs run" ("mechanical, mud, or other"). COGCC Rule 308(a) (2011)
KY	"[E]ntire casing and cementing record, any packers and other special down hole equipment, and cement bond logs, if run" 805 Ky. Admin. Reg. 1:020 Section 4 (2011)
LA	*Search did not locate statute, regulation, or policy addressing this issue.*
MD	Casing and liner record, cement record.[190]
MI	Log including "[t]he amount of cement used and the calculated elevation of the top of the cement." MICH. ADMIN. CODE R 324.418 (2011)
MT	*Search did not locate statute, regulation, or policy addressing this issues (only logs for bottomhole temperature, well location, geological sample logs, mud logs, core descriptions in Mont. Admin. R. 82-11-123 (West 2011)*
NM	In certain counties, must report volume of cement slurry, approx.. temp. when mixed, cement strength at time of casing test. NM ADC 19.15.16 (2011)
NY	Radial cement bond evaluation log "to verify the cement bond on the intermediate and the production casing." R SGEIS 7.1.4.2 (2011)
ND	"[L]og from which the presence and quality of bonding of cement can be determined." ND Admin. Code 43-02-03-31 (2011)
OH	Cement bond log and tickets for each "cemented string of casing." ORC 1509.17(D) (2011)
OK	Required if agency does not witness fracturing operation or in site-specific circumstances.[191]
PA	Cement and bond log. 25 PA ADC 78.74 (2011)
TX	Completion and plugging report, basic electric log, and information on any "change in perforations, or openhole or casing records"; cement log with "complete data concerning the cementing of surface casing in the well as specified on a form furnished by the commission." 16 TAC § 3.16 (b),(c) (2011); 16 TAC § 3.13(b) (2011)
WV	*Search did not locate statute, regulation, or policy addressing this issue.*
WY	Well log, report on well completion. WY ADC OIL GEN Ch. 3 s 12, 21 (2011)

[190] Maryland Well Completion Report, *available at* http://textonly.mde.state.md.us/assets/document/permit/MDE-LMA-PER019-oilgas.PDF.

[191] *See supra* note 176.

Table 4f. Regulation of the well drilling process: Casing, cementing, and blowout prevention: Blowout prevention

AR	Blowout preventers and regular testing of BOPs required. AOGC Rule B-16 (2010). In H_2S areas, "blowout preventers and well control systems shall be pressure tested initially" meet certain psig or burst pressure levels. AOGC Rule B-41(V) (2010)
CO	"The operator shall take all necessary precautions for keeping a well under control while being drilled or deepened." Blowout prevention equip. "shall exceed the anticipated surface pressure to which it may be subjected". Rule 317; high-density areas rig with kelly: double ram with blind ram and pipe ram; annular preventer or a rotating head, rig w/out kelly double ram w/blind ram and pipe ram 2 CCR 404-1 Rule 603 (2011)
KY	"In areas where abnormal pressures are expected or encountered, the surface and/or intermediate casing string shall be anchored in sufficient cement, at a sufficient depth to contain said pressures, and blowout prevention valves and related equipment shall be installed." 805 KAR 1:020 (2011)
LA	Blowout preventer must be installed before installing surface casing, must have certain ram-type preventers appropriate "to control the well under all potential conditions" and drilling spool with side outlets, choke and kill lines, and auxiliary equipment, be tested and maintained so as to control well throughout drilling, workover, "and all other appropriate operations". 43 LA ADC Pt XIX, § 111. Well control safety training required. La. Admin. Code 33:IX.708(C)(1)(b) (2011)
MD	Blowout preventer shall be installed before drilling plug on surface casing, tested to pressure in excess of that expected at production casing point, tested on weekly basis. COMAR 26.19.01.10(Q) (2011)
MI	"[D]ouble ram blowout preventer including pipe and blind rams," accessible controls on rig floor & remote, kelly valve, drill pipe safety valve, flow line; rated working pressure that exceeds max. anticipant pressure. MICH. ADMIN. CODE R 324.406 (2011)
MT	Specific blowout equipment required for wells in formations of unknown pressure (single or double ram w/ at least one pipe and one blind ram, upper and lower kelly cocks, etc.); blowout and well control equip. requ. for all wells (drilling spools to meet certain working pressures). MAR 36.22.1014 (2011)
NM	*Search did not locate statute, regulation, or policy addressing this issue.*
NY	BOP must be maintained and in working order. 6 NYCRR 554.4. BOPE use and test plan required. RSGEIS 7.3.1.2
ND	*Search did not locate statute, regulation, or policy addressing this issue.*
OH	Blowout prevention required in all urban areas and within 200 feet of structures. OAC 1501: 9-9-03. In all areas, casing must provide "base for a blowout preventer or other well control equipment that is necessary to control formation pressures and fluids during the drilling of the well and other operations to complete the well." ORC 1509.17(A) (2011). In Northeastern Ohio, remedial cementing required is annulus pressure exceeds 70% of the hydrostatic pressure at the casing shoe of the surface casing string."[192]
OK	Specific blowout and well control equipment required, must be installed before drilling below surface casing (similar to MT requirements). OAC 165:10-29-1
PA	Blowout prevention required for all Marcellus wells; casing attached to blowout preventer must meet

[192] Ohio Dep't. of Nat. Resources, Oil and Gas Well Permitting Program, Shallow Surface Casing Permit Conditions, *available at* http://www.dnr.state.oh.us/Portals/11/oil/pdf/special_permit_conditions.pdf.

pressure test. 25 Pa. Code 78.72, 78.84 (2011)

TX Blowout prevention "to keep the well under control at all times" required. Equipment must "satisfy any reasonable test which may be required by the commission or its duly accredited agent." 16 TAC § 3.13(b) (2011)

WV "The well operator shall assure that, at all times during the operation of the drilling rig, a person shall be present who has successfully completed a training course on blowout prevention approved by the Chief." W.Va. CSR 35-4-11

WY BOP required for all wells. WY ADC OIL GEN Ch. 3 s 22 (2011). Working pressure of BOP "shall equal or exceed the maximum anticipated pressure to be contained at the surface." Supervisor may require BOPs on case-by-case basis. WY ADC OIL GEN Ch. 3 s 23 (2011). Different technology requirements by PSI system. *Id*.

4.6 Controlling Air Emissions During Drilling and Fracturing

When an oil or gas operator drills and fractures a well, this process emits air pollutants, including nitrogen oxides and volatile organic compounds (VOCs), among others. These pollutants may arise from the following sources:

- wellhead (natural gas leaks)
- flared gas (gas that escapes from the well during drilling and fracturing and is burned)
- equipment used for drilling, fracturing, and dehydrating gas (equipment exhaust)
- pipelines (natural gas leaks);
- flowback water tanks and pits (evaporating volatile organic compounds); and
- compressor stations ("When natural gas leaves a well, it is sent to a gathering station and the gas is then compressed by an internal combustion . . . engine(s) and conveyed to a processing facility via pipeline."[193])

The regulatory process that applies to air pollutants from oil and gas operations is complex, and this paper does not describe this process in depth. Briefly, however, the EPA has established National Ambient Air Quality standards for certain "criteria" pollutants under the Clean Air Act—common pollutants from an array of sources, which endanger public health and welfare.[194] It also has set separate, technology-based standards for hazardous air pollutants, or HAPs, which cause serious and chronic human health effects, such as cancer.[195] Oil and gas development emits both criteria and hazardous air pollutants. These pollutants often face little regulation under the Clean Air Act, however, because the Act focuses most of its controls on "major" sources, which are defined as sources that emit a certain number of tons per year of a pollutant, and particularly on new sources. Oil and gas operations often are minor sources and are thus regulated—if at all—under state minor source programs. (States have been delegated regulatory authority under

[193] Governor's Marcellus Shale Advisory Commission, *supra* note 125, at § 7.3.2
[194] *See generally* 42 U.S.C. §§ 7408-9 (2011).
[195] *See generally* 42 U.S.C. §7412 (2011).

the Clean Air Act and implement their own regulations above a federally-imposed floor.) Oil and gas operations—even minor ones—tend to face the strictest regulations in "nonattainment" areas—those areas that have exceeded the National Ambient Air Quality Standard (NAAQS) for a criteria pollutant and that require control of all air pollution sources.

The EPA's current methodology for defining "major" sources[196] could bring many more oil and gas sites beneath the major source umbrella, even in relatively clean "attainment" areas. A major source includes "any group of stationary sources located within a contiguous area and under common control" that emits a certain number of tons of regulated pollutant annually.[197] Newly-built and existing compressor stations that make a modification and increase their hourly emissions already are subject to new source performance standards (technology-based emissions controls) for "stationary spark ignition internal combustion engines."[198] The EPA also has proposed regulations that will establish new source performance standards (NSPS) for VOCs emitted from fractured wells and those that are "refractured"—referring to circumstances in which an operator returns to the well after one fracturing operation to fracture the well again and enhance oil or gas production. [199] The EPA partially based is proposed VOC controls on Colorado's and Wyoming's air quality regulations for oil and gas wells (including fractured

[196] *See* Memorandum from Gina McCarthy, Assistant Administrator to Regional Administrators, Withdrawal of Source Determinations for Oil and Gas Industries, Sept. 22, 2009, *available at* http://www.epa.gov/region7/air/nsr/nsrmemos/oilgaswithdrawal.pdf.

[197] 42 U.S.C. § 7661 (West 2011). (This definition comes from Title V of the Clean Air Act, which describes which sources of criteria pollutants (regulated pollutants emitted by stationary sources) must obtain Title V operating permits. Title V permits pull together various Clean Air Act permitting requirements (emission controls on criteria pollutants emitted from new and modified stationary sources and on hazardous air pollutants, for example) within one permit. Stationary sources of air pollutants do not face much regulation under the Clean Air Act unless they are: 1) major, and, in the case of criteria (non-hazardous) air pollutants, 2) modified or new. If a source meets these two criteria, it will face emission limitations under the "new source review" provisions under the Clean Air Act and will have to obtain a Title V permit. Some states also regulate minor sources, however, as discussed in the text.

[198] *See* Governor's Marcellus Shale Advisory Commission, *supra* note 125, at § 7.3.1 (citing 40 CFR Part 63, Subpart ZZZZ).

[199] 76 C.F.R. 52738, Aug. 23, 2011, Oil and Natural Gas Sector: New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants Reviews, Proposed Rule.

wells),[200] which already require some emissions reductions. Colorado, for example, amended its VOC regulations in 2006 "to include state wide control requirements for emission sources applicable to the oil and natural gas industry."[201] Under the current regulations, condensate tanks, crude oil, and produced water tanks with the potential to emit five tons per year or more of VOCs must capture 95% or more of their VOCs in certain counties and within certain distances of buildings such as jails, nursing homes, and schools.[202] Glycol dehydrators and pits in these same areas with the same potential VOC emissions must capture 90 percent of more VOCs.[203] All wells that have the potential to emit certain quantities of hydrocarbon gas must use green completion practices.[204]

At the state level, New York (followed closely by Colorado) has perhaps gone the furthest in regulating emissions from drilling and fracturing. It has proposed to limit "the maximum number of wells to be drilled and completed annually or during any consecutive twelve-month period at a single pad" to four.[205] New York further intends to prohibit the simultaneous operation of drilling and fracturing engines at one well pad, and to require diesel "used in drilling and hydraulic fracturing engines" to be "limited to ULSF [ultra-low sulfur diesel] with a maximum sulfur content of 15 ppm,"[206] and it has proposed several additional air quality controls[207] and greenhouse gas emission mitigation requirements.[208] Echoing the EPA's proposed regulations for VOCs, New York also has proposed to require vapor recovery systems on condensate tanks "to minimize fugitive VOC emissions." At the flowback stage, New York also would limit the

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[200] 76 F.R. 52738, 52757 (2011), *available at* http://www.gpo.gov/fdsys/pkg/FR-2011-08-23/pdf/2011-19899.pdf (looking to Colorado and Wyoming's mitigation measures).
[201] Ty J. Smith, *Colorado Minor Source Permitting*, 2007 No. 5 ROCKY MOUNTAIN MINERAL LAW FOUNDATION-INST. PAPER No. 3C at 1 (Nov. 1-2, 2007).
[202] COGCC Rule 805(b)(2).
[203] *Id*.
[204] COGCC Rule 805(b)(3).
[205] New York Preliminary Revised Supplemental Generic Environmental Impact Statement, *supra* note xx, at 7-108.
[206] *Id*.
[207] *Id*.
[208] R SGEIS § 7.6.8.

venting of gas to "a maximum of 5 MMscf during any consecutive 12-month period."[209] Beyond limited minor source regulations, many other states do not have these types of controls. At most, they require stacks on drilling and fracturing rigs to be of a minimum height, thus seeking to partially prevent air pollution from concentrating in the local area in the vicinity of the emission source.

Some municipalities also have imposed air quality requirements on gas wells and their associated facilities, such as pits and tanks. Fort Worth, Texas, for example, requires storage tanks that, in the aggregate, emit 25 tons of more of volatile organic hydrocarbons annually to install vapor recovery systems that capture 95% of VOCs.[210] Fort Worth also requires that certain well operators employ "Reduced Emission Completion" techniques, meaning that operators should avoid releasing gas into the air.[211] Finally, it requires exhaust mufflers to reduce noise from equipment and to "prevent the escape of obnoxious gases, fumes or ignited soot."[212]

At minimum, states should evaluate and monitor emissions from oil and gas drilling and fracturing operations and ensure that these emissions are not contributing to existing nonattainment problems or causing air quality problems in adjacent, clean areas. Texas has implemented an extensive air monitoring program in the Barnett Shale, for example, which provides up-to-date online emissions data.[213] Pennsylvania also has conducted limited, short-term ambient air monitoring in the Marcellus Shale region.[214] Substantive regulatory revisions also may be needed depending on the results of monitoring. Although space limitations prohibit a more detailed discussion of existing air regulations and the need to revise them in light of the

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[209] *Id*. at § 7.5.3.1.

[210] City of Fort Worth, Ordinance No. 18449-02-2009 § 15-42 A.36, *available at* http://fortworthtexas.gov/uploadedFiles/Gas_Wells/090120_gas_drilling_final.pdf.

[211] *Id*. at § 15-42 A.28.

[212] *Id*. at § 15-42 A.25.

[213] Texas Comm'n on Envtl. Quality, Barnett Shale Emissions: Data Collection and Analysis, http://www.tceq.texas.gov/airquality/barnettshale/bshale-data.

[214] Northeastern Pennsylvania Marcellus Shale Short-Term Ambient Air Monitoring Report, Jan. 12, 2011, http://www.dep.state.pa.us/dep/deputate/airwaste/aq/aqm/docs/Marcellus_NE_01-12-11.pdf.

thousands of new oil and gas wells contributing to air pollution, air quality issues appear require much more regulatory attention than they have so far received.

Tables 5a and 5b provide examples of state air quality regulations for drilled and fractured wells and more general regulations, which, while not controlling the amount of air emissions, reduce localized air pollution. The examples include:

- Requirements for rig and dehydrator stack heights, condensate tank vapor recovery, exhaust muffling
- Gas venting and flaring (during drilling and/or flowback), VOC capture

Table 5a. Air emission controls during drilling and fracturing: Requirements for rig and dehydrator stack heights, exhaust muffling

AR	No gas requirements, but H_2S from storage tanks must be recovered through vapor recovery unit or flared through flare stack with permanent pilot (if H_2S > 100 ppm). AOGC Rule B-41 (2010)
CO	Exhaust shall be vented away from all building units COGCC Rule 801; must meet Air Quality Control Commission Reg. No. 2 for Odor Emission, 5 C.C.R. 1001-4. Operators must obtain permission under general permits for condensate and produced water tanks; statewide, condensate tanks emitting 20 tpy or more VOCs must capture 95% VOCs.[215]
KY	*Search did not locate statute, regulation, or policy addressing this issue.*
LA	Exhaust discharged only if engine or compressor has exhaust muffler or exhaust box (urbanized areas) Order No. U-HS
MD	*Search did not locate statute, regulation, or policy addressing this issue.*
MI	*Search did not locate statute, regulation, or policy addressing this issue.*
MT	In certain areas, good engineering practice stack heights required. MAR 17.8.402 (2011)
NM	*Search did not locate statute, regulation, or policy addressing this issue.*
NY	Min. stack height for dehydrator 30 ft. if wet gas encountered; drilling rigs and air compressors EPA tier 2 or newer equipment; Non-Selective Catalytic Reduction controls on wellhead compressors; and others R SGEIS Attachment A (p. 1352); *id*. at 1-15
ND	*Search did not locate statute, regulation, or policy addressing this issue.*
OH	*Search did not locate statute, regulation, or policy addressing this issue.*
OK	*Search did not locate statute, regulation, or policy addressing this issue.*
PA	*Search did not locate statute, regulation, or policy addressing this issue.*
TX	*Search did not locate statute, regulation, or policy addressing this issue.*
WV	*Search did not locate statute, regulation, or policy addressing this issue.*
WY	*Search did not locate statute, regulation, or policy addressing this issue.*

[215] Air Pollution Control Division, Oil and Gas Regulatory Information, http://www.cdphe.state.co.us/ap/oilgas.html.

Table 5b. Air emission controls during drilling and fracturing: Gas venting and flaring (during drilling and/or flowback), VOC capture, compressor station permitting

AR	*Search did not locate statute, regulation, or policy addressing this issue.*
CO	Condensate, produced water tanks w/ potential to emit 5 tpy or more of VOCs in certain counties must have 95% VOC control efficiency; pits w/ this emission potential must be >1/4 mile from buildings; glycol dehydrators w/ this emissions potential must control VOCs by 90% COGCC Rule 805; gas from drilling must be conducted "safe distance" from well site and burned. AOGC Rule 317
KY	*Search did not locate statute, regulation, or policy addressing this issue.*
LA	Must "minimize gas releases into the open air," flaring allowed, but no open flame w/in 200 ft. of building (urbanized areas). Order No. U-HS
MD	*Search did not locate statute, regulation, or policy addressing this issue.*
MI	*Search did not locate statute, regulation, or policy addressing this issue.*
MT	*Search did not locate statute, regulation, or policy addressing this issue.*
NM	*Search did not locate statute, regulation, or policy addressing this issue.*
NY	Venting during flowback max of 5 MMscf during consecutive 12-mo. pd. R SGEIS 7.5.3.1 (2011)
ND	*Search did not locate statute, regulation, or policy addressing this issue.*
OH	*Search did not locate statute, regulation, or policy addressing this issue.*
OK	Up to 50 mcf/d without a permit if meet certain conditions. OCC 165:10-3-15; "Suitable" stack must be used for flaring "to prevent a hazard to people or property". OAC 165:10-3-15
PA	General permit for Natural Gas, Coal Bed Methane, or Gob Gas Production or Recovery Facilities (GP-5) if < 1,500 HP engine; larger units subject to best available technology emission limitations[216]
TX	*Search did not locate statute, regulation, or policy addressing this issue.*
WV	*Search did not locate statute, regulation, or policy addressing this issue.*
WY	*Search did not locate statute, regulation, or policy addressing this issue.*

[216] Governor's Marcellus Shale Advisory Commission, *supra* note 125, at § 7.3.2.

4.7 Withdrawing Water for Fracturing

Many of the regulations discussed to this point apply to all types of oil and gas development—not just fractured wells. To varying degrees, states regulate the construction of access roads and well pads, the location of well pads and associated facilities, the casing and cementing of drilled wells, and air emissions from well activity, and these regulations are not typically fracturing-specific. Indeed, in many cases, these regulations were not written in anticipation of widespread horizontal drilling and fracturing and therefore may not have predicted some of the indirect changes that fracturing introduces to the typical stages of well development, such as increasing the number of wells per pad and the depth of the well drilled.

Fracturing also introduces several new stages to the well development process—stages, which, unlike those discussed to this point, are typically unique to fractured wells in shales and tight sands.. First, states must regulate or monitor the millions of gallons of water that fracturing operators must withdraw for fracturing (in addition to water withdrawn for drilling muds and fluids used at the drilling stage).[217] States also increasingly require the disclosure of chemicals that are mixed with water just prior to the fracturing process. Some have revised their regulations to address fracturing itself—the process of injecting the water-chemical solution into the well at high pressure. This section discusses regulation of water withdrawal for us in slickwater fracturing, and the following section describes chemical disclosure and fracturing-specific controls.

The issue of water use is one of the greatest challenges faced by states experiencing increased rates of slickwater fracturing. The Railroad Commission of Texas, for example, has noted that "[i]ncreasing water use due to growing population, drought, and Barnett Shale development has heightened concerns about water availability in North-Central Texas."[218] Drilling alone can

[217] *See infra* notes 219-220.

[218] Railroad Comm'n of Texas, Water Use in the Barnett Shale, Jan. 24, 2011, http://www.rrc.state.tx.us/barnettshale/wateruse_barnettshale.php.

require "up to 300,000 gallons [of water] per day per well,"[219] and each fracturing treatment requires between 1.2 and seven million gallons of water, or more.[220] The laws that control this water use—which are generally tailored toward water consumption more generally, and not to drilling and fracturing—have historically varied dramatically as a result of states' varied development trajectories.

Regardless of the state in which an operator drills a well, he or she must obtain water rights before withdrawing water or must purchase water from someone who has water rights and is permitted to sell water withdrawn under those rights. Each state's common law governs the exercise of these rights,[221] and the common law follows roughly regional lines. Generally, eastern states are dominated by riparian regimes in which those who own land abutting resources have limited rights to use of the water,[222] while western states tend to follow a prior appropriation regime in which those who first put water to beneficial use maintain a right to continued use of the water.[223] Other states follow a hybrid riparian-prior appropriation approach.[224] As described

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[219] Penn State College of Agricultural Sciences, Agricultural Research and Cooperative Extension, Water Withdrawals for Development of Marcellus Shale Gas in Pennsylvania 3 (2009), *available at* http://pubs.cas.psu.edu/freepubs/pdfs/ua460.pdf.

[220] *See* J.A. Harper, *The Marcellus Shale – An Old "New" Gas Reservoir*, 38 PA. GEOL. 1, 12 (2008), http://www.dcnr.state.pa.us/topogeo/pub/pageolmag/pdfs/v38n1.pdf (estimating that "[b]ased on information from the Barnett Shale play, a horizontal well completion might use more than 3 million gallons"); NY DEC Preliminary Revised SGEIS, *supra* note xx, at 8 ("It is estimated that 2.4 million to 7.8 million gallons of water may be used for a multi-stage hydraulic fracturing procedure in a typical 4,000-foot lateral wellbore."); Railroad Commission of Texas, Water Use in the Barnett Shale, Jan. 24, 2011, http://www.rrc.state.tx.us/barnettshale/wateruse_barnettshale.php ("Slick water fracing of a vertical well completion can use over 1.2 million gallons (28,000 barrels) of water, while the fracturing of a horizontal well completion can use over 3.5 million gallons (over 83,000 barrels) of water. In addition, the wells may be re-fractured multiple times after producing for several years.").

[221] *Cf.* R. Timothy Weston, *Water and Wastewater Issues in Conducting Operations in a Shale Play: The Appalachian Basin* Experience, 2010 No. 5 Rocky Mountain Mineral Law Foundation Institute Paper No. 4, Development Issues in the Major Shale Plays at 9 (Dec. 6-7, 2010) (explaining that in the Marcellus, "common law doctrines and tradition remain strong" despite regulatory programs displacing these doctrines in some cases).

[222] *Id*. at 10.

[223] See Henry Smith, Governing Water: The Semicommons of Fluid Property Rights, 50 Ariz. L. Rev. 445, 447 (2008).

[224] *See* Shelley Ross Saxer, *The Fluid Nature of Property Rights in Water*, 21 DUKE ENVTL. L. & POL'Y F. 49, 55 (2010).

by R. Timothy Weston, in a riparian regime like Pennsylvania's (in an area without additional regulations, such as those imposed by river basin commissions) an operator who drills on land adjacent to surface water will be able to use that water, provided that it does not illegally impede others' reasonable use; the operator also may use groundwater beneath the leasehold, again subject to a "reasonable use" limitation.[225] Operators who need to import water from beyond the site will encounter more hurdles, as the common law may prevent riparian owners from selling their water to the operator.[226]

Many states have augmented or replaced the common law with statutes and regulations, which add permitting and reporting requirements to the water withdrawal process.[227] Space limitations prohibit a full discussion of these varied regimes, but as a general matter, operators face a variety of legal scenarios. In some states, operators must obtain both water rights and a permit to withdraw water and are limited in the quantities that they withdraw. They also may need to periodically report the quantities of water withdrawn to a state entity. In other states, operators face few controls on withdrawal and, after ensuring that they have the necessary water rights to cover their withdrawal, may simply begin pumping.

Pennsylvania's water use regime provides an example of a relatively complex system, based both in the common law and regulation, which governs water withdrawals for hydraulic fracturing. Water use in the state is partially governed by a common law riparian scheme, which provides, generally, that landowners abutting surface water are entitled to an undiminished natural flow of water subject to the reasonable use of other riparian owners.[228] This means that Groundwater use

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[225] Weston, *supra* note 221, at 31.

[226] *Id*.

[227] *See* Weston, *supra* note 221, at 9 (noting that despite the strength of the common law in the Marcellus, "common law has been supplemented, and to a significant degree supplanted by, statutory enactments establishing regulatory permitting systems").

[228] Michael Dillon, Comment, *Water Scarcity and Hydraulic Fracturing in Pennsylvania: Examining Pennsylvania Water Law and Water Shortage Issues Presented by Natural Gas Operations in the Marcellus* Shale, 84 TEMP. L. REV. 201, 214 (2011) (citing Clark v. Pennsylvania R. Co., 22 A. 989, 990 (Pa. 1891)).

is subject to a similar reasonable use doctrine.[229] Beyond the common law doctrine that limits withdrawals by defining the water rights that must be obtained, "No state statute or regulatory program comprehensively addresses the allocation of use of ground or surface waters among competing users, or provides for long-term management of water resources."[230] Operators withdrawing ground or surface water for fracturing, however, are subject to several regulatory mechanisms. Under the state's Clean Streams Law, which protects water quality, and the Oil and Gas Act, the state's Department of Environmental Protection has "claimed authority . . . t o review and approve 'water management plans' governing water sources utilized by Marcellus Shale gas operators."[231] The State Review of Oil and Natural Gas Environmental Regulation's review of Pennsylvania's hydraulic fracturing program noted the strength of Pennsylvania's program, explaining:

> In 2008, . . . [Pennsylvania] began requiring water management plans to identify where water would be withdrawn and the volumes of withdrawal. The purpose of this inquiry is to ensure that water quality standards are maintained and protected. . . . Because large withdrawals can, individually or cumulatively, impact water quality, DEP must assure that excessive withdrawals do not occur. DEP follows water quality guidance promulgated by the Susquehanna River Basin Commission (SRBC to ensure uniform statewide evaluation.[232]

Under a water management plan, an operator in Pennsylvania must describe the source from which water may be withdrawn (surface water; groundwater; wastewater, mine water, or cooling water discharge; or a public water supply); the location of the source, the average daily quantity proposed to be withdrawn in gallons per day, and the maximum withdrawal rate in gallons per minute.[233] If the "total water withdrawn from listed sources and other sources operated by the gas

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[229] *Id*.

[230] Weston, *supra* note 221, at 18.

[231] *Id*.

[232] State Review of Oil & Natural Gas Envtl. Regulations, Pennsylvania Hydraulic Fracturing State Review 4, Sept. 2010, *available at* http://www.strongerinc.org/documents/PA%20HF%20Review%20Print%20Version.pdf.

[233] Pennsylvania Dep't of Envtl. Protection, Water Management Plan for Marcellus Shale Gas Well Development Example Format at 1, http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-74084/5500-PM-OG0087%20Application%20Example.pdf.

well operator in the same watershed" will exceed an average of 10,000 gallons per day within "any 30-day period,"[234] the operator must register with the Department of Environmental Protection and "annually report their water usage."[235] Within the water management plan, operators also must conduct a low flow analysis describing the "average daily flow of stream at point of withdrawal" in gallons per day and other flow statistics; a "withdrawal impacts analysis" describing "how the surface withdrawal intake will be designed and operated to minimize entrainment and impingement of fish and other aquatic life," among other impacts; and a natural diversity inventory, among other required data and analyses.

Operators in Pennsylvania withdrawing surface water or groundwater within the watersheds of the Susquehanna and Delaware Rivers are subject to additional regulation (as are operators in portions of other states that fall within these watersheds). The Delaware and Susquehanna River Basin Commissions—regional regulatory bodies that operate under congressionally-approved federal compacts—have the power to protect water quality and quantity within their watersheds,[236] and any operator proposing to withdraw threshold quantities[237] of ground or

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[234] *Id*.

[235] Pa. Dep't. of Envtl. Protection, Water Use Registration and Reporting, http://www.pawaterplan.dep.state.pa.us/StateWaterPlan/WaterUse/WaterUse.aspx.

[236] *See* Delaware River Basin Compact, *supra* note 87, at § 10.1 (providing that "[t]he commission may regulate and control withdrawals and diversions from surface waters and ground waters of the basin"); *id*. at § 5.3 (providing that each of the signatory parties "agrees to prohibit and control pollution of the waters of the basin according to the requirements of this compact"); *id*. at § 5.5 (allowing the Commission to enforce, "after investigation and hearing," its rules that it has "adopted for the prevention and abatement of pollution"); Susquehanna River Basin Compact, *supra* note 88, at § 11.1 (providing that "[t]he commission may regulate and control withdrawals and diversions from surface waters and ground waters of the basin"); *id*. at § 5.2 (providing that the commission shall "encourage and coordinate the efforts of the signatory parties to prevent, reduce, control, and eliminate water pollution and to maintain water quality," and, although leaving primary water quality authority to the states, allowing the Commission to "assume jurisdiction" over water quality when its comprehensive plan so requires and it conducts and investigation and provides public notice).

[237] The threshold quantity for the SRBC is "100,000 gallons per day (gpd) or more (based on a 30-day average) or "the consumptive use of 20,000 gpd or more (also based on a 30-day average"). Susquehanna River Basin Comm'n, Accommodating a New Straw in the Water: Extracting Natural Gas from the Marcellus Shale in the Susquehanna River Basin 2 (2009), *available at* http://www.srbc.net/programs/docs/Marcellus%20Legal%20Overview%20Paper%20%28Beauduy%29.pdf.PDF. Any "diversions from the basin" are consumptive uses, as are uses that involve injection of water that will "not reasonably be available for future use in the basin. *Id*. All withdrawals for fracturing are considered consumptive

surface water from a basin watershed accordingly must first obtain approval from the commission with jurisdiction.[238] The Susquehanna River Basin Commission determines the quantity allowed to be withdrawn based on "reasonably foreseeable need," which looks to water availability and the needs of the specific operator and prohibits withdrawals that will have adverse impacts, such as degraded water quality, effects on fish and wildlife, or "excessive lowering of water levels."[239] It also limits consumptive withdrawals based on cumulative adverse impacts of water use,[240] requiring one-to-one mitigation of impacts by, for example, reducing or suspending withdrawals during periods of low water flow.[241] Proposed regulations of the Delaware River Basin Commission also would specify the types of sources from which operators could withdraw water and, for certain sources, the quantity that could be withdrawn, as measured by the minimum pass-by flow conditions that must be maintained within the stream from which the operator is withdrawing.[242] Proposed regulations of the Susquehanna River Basin Commission, in turn, would make recycling and reuse of flowback water easier—providing for a faster means of approving diversions of flowback water for use at another site.[243]

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uses. Thomas W. Beauduy, *"Shale" We Drill? The Legal and Environmental Impacts of Extracting Natural Gas from Marcellus* Shale, 22 VILLANOVA ENVTL. L. J. 189, 217 (2011) (explaining that "one hundred percent of the water that goes down the bore hole is considered lost to the basin")

[238] 18 C.F.R. § 806.4(a)(8) (2011); Delaware River Basin Commission, Natural Gas Development Regulations (proposed) § 7.3, Dec. 9, 2010, *available at* http://www.state.nj.us/drbc/naturalgas-draftregs.pdf (requiring individual review of "[w]ater withdrawals and water use for natural gas development"). Note that under the draft rules, certain withdrawals could be approved via "approval by rule" rather than an individual docket. *See generally id*.

[239] Susquehanna River Basin Comm'n, *supra* note 237, at 2. *See also* 18 C.F.R. § 806.23(b)(1) (West 2011).

[240] 18 C.F.R. §806.23)West 2011); Susquehanna River Basin Commission, Frequently Asked Questions, SRBC's Role in Regulating Natural Gas Development, Sept. 2011, http://www.srbc.net/programs/docs/FAQ%20September%202011%20Final%20-%20SRBC%27s%20Role%20in%20Regulation%20Natural%20%20Gas%20Development.PDF.

[241] Susquehanna River Basin Comm'n, *supra* note 237, at 2-3.

[242] Del. River Basin Comm'n, *supra* note 109, at § 7.4 (d)(xi) (passby flow conditions).

[243] 76 Fed. Reg. 41154, July 13, 2011, *available at* http://www.srbc.net/programs/docs/Proposed%20Rulemaking%20%28as%20published%20in%20Fed%20Reg%29%2007-13-11.pdf. The document provides an "approval by rule" of certain diversions, which allows the Executive Director of the SRBC to approve diversions.

The several layers of law and regulation that apply to water withdrawals for fracturing in Pennsylvania are just one model; other state approaches vary substantially. Like the regional Susquehanna River Basin Commission, however, several states have revised their regulations to encourage recycling and reuse of flowback water, as shown in Figure 1. When operators reuse flowback water, this can substantially reduce the amount of freshwater that must be withdrawn for drilling and fracturing as well as the waste generated.

In contrast to Pennsylvania's approach, states such as Kentucky—although requiring a permit for water withdrawals exceeding an average daily flow of 10,000 gallons per day[244]—provide that no permit shall be required for withdrawing water to be injected for oil and gas operations.[245] It is not clear whether Kentucky includes hydraulic fracturing in its definition of "injection," however, and this will be an important consideration if fracturing expands in the state.

In other states, operators need not obtain a permit before withdrawing water but still must report the quantity of water that they propose to withdraw or actually withdrew for hydraulic fracturing. All states should consider, at minimum, requiring this type of reporting to better understand the

Figure 1. Regulatory Provisions that Allow and/or Encourage Recycling and Reuse of Flowback

[244] Weston, *supra* note 221, at 16 (citing to Ky. Rev. Stat. § 151.150(1).
[245] *See infra* Table 6.

Arkansas: All Hydraulic Fracturing Treatment flow back fluids shall be handled, transported, stored, disposed, or recycled for re-use . . . ." AOGC Rule B-19(j) (2010).

Oklahoma: Offers "reclaim and/or recycle" as a flowback disposal option. 165 10-7-24 (b)(3), (c)(1) (2011).

Pennsylvania: "A wastewater source reduction strategy shall be developed by the well operator by August 22, 2011, and submitted to the Department upon request. The source reduction strategy must identify the methods and procedures the operator shall use to maximize the recycling and reuse of flow back or production fluid either to fracture other natural gas wells, or for other beneficial uses." 25 Pa. Code § 95.10 (2011).

SRBC: "The interbasin diversion of any flowback or production fluids from hydrocarbon development projects from one drilling pad site to another drilling pad side for use in hydrofracture stimulation, and handled in such a manner as to isolate it from waters of the basin, shall not be subject to separate review and approval ad a diversion . . . if the generating or receiving pad site is subject to an Approval by Rule . . . ." 18 C.F.R. § 806.4

quantity of water needed for fracturing and to project and minimize potential future conflicts among water users. As the State Review of Oil and Natural Gas Regulations observes in Colorado:

> [T]he [Colorado Oil and Gas Conservation Commission] and the [Division of Water Resources should] jointly evaluate available sources of water for use in hydraulic fracturing. Given the significant water supply issues in this arid region, this project should also include an evaluation of whether or not availability of water for hydraulic fracturing is an issue and, in the event that water supply is an issue, how best to maximize water reuse and recycling for oil and gas hydraulic fracturing.[246]

States also should consider implementing certain controls on water withdrawals, such as minimum pass-by flow requirements, to ensure that sufficient water remains in surface supplies to protect aquatic fish, plants, and wildlife and to help maintain water quality. While states' water law systems vary substantially, and in many cases will not accommodate these types of provisions without substantial and likely controversial statutory amendment, states should consider other creative ways of ensuring that water withdrawals for fracturing—particularly during drought periods—do not adversely impact water supplies. Tables 6a and 6b provide

[246] State Review of Oil & Natural Gas Envtl. Regulations, Colorado Hydraulic Fracturing State Review 7, Oct. 2011, *available at* http://www.strongerinc.org/documents/Colorado%20HF%20Review%202011.pdf.

examples of state and regional regulation of water withdrawals and water use reporting. Note that the table omits requirements of the Great Lakes – St. Lawrence River Basin Water Resources Compact, which applies to "sections of western New York, northwestern Pennsylvania, and northeastern Ohio" that overlie the Marcellus Shale.[247] Some states have progressed further than others in implementing this compact, which requires states to require applications for new or increased water withdrawals and "consumptive uses and diversions,"[248] and to establish registration program for all withdrawals exceeding 100,000 gallons per day over any thirty-day period.[249]

[247] Weston, *supra* note 221, at 29.

[248] Great Lakes-St. Lawrence River Basin Water Resources Compact § 4.3 (Dec. 13, 2005), *available at* http://www.cglg.org/projects/water/docs/12-13-05/Great_Lakes-St_Lawrence_River_Basin_Water_Resources_Compact.pdf.

[249] *Id*. at § 4.1.

Table 6a. Withdrawing water for fracturing: water withdrawal permits and other requirements

AR	*Search did not locate statute, regulation, or policy addressing this issue.*
CO	Disinfection of water suction hoses and water transportation tanks in Cutthroat Trout habitat. COGCC Rule 1204. If outside designated ground water basin, permit from state engineer for groundwater withdrawal. CO Stat. § 37-90-137 (2011). Water right through adjudication process of substitute water supply plan fr. state engineer. CO Stat. § 37-92-308
KY	No permit required for withdrawing water to be "injected underground in conjunction with operations for the production of oil or gas." KRS 151.140 (2011)
LA	Conservation Commissioner "recommends" that Red River Alluvial aquifer be used if groundwater must be pumped, "encourages" use of available surface waters."[250]
MD	Water appropriation and use permit required for surface and groundwater withdrawals.[251]
MI	Withdrawal of water for oil and gas exempt from state regulation, [252] but the state appears to prohibit the use of surface water for drilling fluid unless there is an emergency. MICH. ADMIN. CODE R 324.404 (2011).
MT	*Search did not locate statute, regulation, or policy addressing this issue.*
NM	Submit application for beneficial use to state engineer. NM Stat. § 72-12-3 (2011)
NY	Avoid degradation of water qu. as result of water withdrawal. R SGEIS at 7.1.1.1 DRBC: low-flow requ. + permit; prohibition of any alteration in flow that would impair a fresh surface water body's designated best use". Rev. SGEIS 7.1.1.1; permit requ. before withdraw surface water 6 NYCRR § 601.3 (2011); Great Lakes-St. Lawrence River Basin Water Resource Compact (GLSB): withdrawal permitting for 100,000 gpd withdrawn over 30 days[253]
ND	*Search did not locate statute, regulation, or policy addressing this issue.*
OH	Permit required for "new or increased consumptive use" > 2 mill. gallons/day averaged over thirty days ORC § 1501.33 (2011) ; GLSB withdrawal permitting for 100,000 gpd withdrawn over 30 days[254]
OK	*Search did not locate statute, regulation, or policy addressing this issue.*

[250] Louisiana Department of Natural Resources, Ground Water Use Advisory: Commissioner of Conservation Recommends Wise Water Use Planning in the Haynesville Shale, Oct. 16, 2008, http://dnr.louisiana.gov/index.cfm?md=newsroom&tmp=detail&aid=509.

[251] Md. Dep't of the Env't, Application for Gas Exploration and Production, *available at* http://www.mde.state.md.us/assets/document/permit/MDE-LMA-PER045.pdf.

[252] *See* State of Michigan, Dep't of Envtl. Quality, Supervisor of Wells Instruction 1-2011, http://www.michigan.gov/documents/deq/SI_1-2011_353936_7.pdf.

[253] This is the default permitting requirement contained in the Great Lakes-St. Lawrence River Basin Water Resources Compact. *See* Weston, *supra* note 221, at 29-30 (citing Pub. Law 110-342, 122 Stat. 3749 and noting that the Compact is still in the early stages of implementation within the participating states, with the exception of Pennsylvania).

[254] *See id*.

PA DRBC: passby requ. + permit; SRBC: permit; GLSB permitting for withdrawal equal to or greater than 100,000 gpd averaged over 90 days or any new or increased consumptive use equal to or greater than 5 million gpd averaged over 90 days. 32 PSA 817.23

TX *Search did not locate statute, regulation, or policy addressing this issue.*

WV Must "ensure that all uses of the waters are protected."[255] All users of more than 750,000 gallons of water per month must register with WV DEP and provide information on water withdrawals. W. Va. Code §§ 22-26-2, 22-26-3 (West 2011). No statewide permitting requirement.[256]

WY *Search did not locate statute, regulation, or policy addressing this issue.*

[255] West Virginia Dep't of Envtl. Protection, Industry Guidance, *supra* note 126, at 3.

[256] Weston, *supra* note 221, at 23 (indicating in 2010 that "West Virginia has not adopted a regulatory program addressing either surface or groundwater withdrawals").

Table 6b. Withdrawing water for fracturing: water withdrawal reporting

AR	*Search did not locate statute, regulation, or policy addressing this issue.*
CO	Must report total volumes used under proposed rule 205A.
KY	*Search did not locate statute, regulation, or policy addressing this issue.*
LA	Water source and associated volume.[257]
MD	Estimated amounts of water to be used for drilling, hydraulic fracturing (each in gpd); "source and location of withdrawal point of water."[258]
MI	Water withdrawal evaluation, daily monitoring of water levels in water wells w/in 1,320 ft. of water withdrawal.[259]
MT	*Search did not locate statute, regulation, or policy addressing this issue.*
NM	*Search did not locate statute, regulation, or policy addressing this issue.*
NY	Identify source and qty. of water intended for use. R SGEIS 7.1.1.1 (2011). DRBC: extensive monitoring and reporting required (proposed); SRBC: daily monitoring, quarterly reporting of use required[260]
ND	*Search did not locate statute, regulation, or policy addressing this issue.*
OH	*Search did not locate statute, regulation, or policy addressing this issue.*
OK	*Search did not locate statute, regulation, or policy addressing this issue.*
PA	See NY for DRBC and SRBC; Annual Act 220 water use reports required[261]
TX	"Total volume of water used in hydraulic fracturing treatment." H.B. 3328 (2011) (enacted).
WV	Report anticipated volumes and actual volumes used.[262]
WY	*Search did not locate statute, regulation, or policy addressing this issue.*

[257] Memorandum from James H. Welsh, Commissioner of Conservation, to "All Concerned," Reporting Requirements for Water Use in E&P Operations, Sept. 15, 2009.

[258] http://www.mde.state.md.us/assets/document/permit/MDE-LMA-PER045.pdf.

[259] *See supra* note xx (Michigan Dep't of Envtl. Quality Instruction 1-2011).

[260] Natural Gas Well Development in the Susquehanna River Basin, http://www.srbc.net/programs/docs/ProjectReviewMarcellusShale%28NEW%29%281_2010%29.pdf.

[261] Pennsylvania's Act 220, Pa. State Water Plan Update, http://www.state.nj.us/drbc/wateruse/PAact220.htm.

[262] West Virginia DEP, Industry Guidance, Gas Well Drilling/Completion, *supra* note 126, at 2.

4.8 Fracturing the Well

In addition to withdrawing water and transporting it to a site to fracture a well, an operator must bring chemicals to the site to mix with water and form a fracture solution. As discussed in Professor Duncan's white paper, the transportation of chemicals and their transfer to water on site poses one of the highest potential risks for environmental harm. The fracturing chemicals, many of which are hazardous and are not diluted at the transportation stage, could cause environmental and health damage if spilled—particularly if spilled near surface water or a conduit to groundwater. In Oklahoma in December 2011, for example, a truck carrying 4,500 gallons of hydrochloric acid had a loose fitting and began leaking onto a highway, necessitating the evacuation of about 500 people.[263] Although reports of the spill did not indicate the ultimate destination or purpose of the hydrochloric acid, a similar incident could potentially occur during the transport of hydrochloric acid and other chemicals to fracture sites.

The regulation of the transportation of hazardous chemicals, including those used for fracturing, occurs primarily at the federal level. Department of Transportation hazardous transport regulations apply to the shipment of chemicals. They require that trucks be labeled with appropriate information and that transport containers be constructed with certain materials of certain thickness, among a number of other requirements.[264] In addition to federal regulation, municipalities also may control the routes on which hazardous chemicals are transported,[265] thus limiting the risks of spills to certain areas.

Beyond regulating the shipment of chemicals to the site, some states have implemented general provisions requiring that fracturing not pollute water, as indicated in Figure 2. Although such

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[263] Amanda Bland, *Acid Leak Reroutes Traffic; Residents Evacuated*, TULSA WORLD, Dec. 15, 2011, *available at* http://www.tulsaworld.com/news/article.aspx?subjectid=11&articleid=20111215_82_A10_ULNSof222040.

[264] 49 C.F.R. §§ 171-180. *See* R SGEIS at 8.1.3.1 for a description of the federal Hazardous Material Transportation Act and the Hazardous Materials Transportation Uniform Safety Act and their applicability to the transportation of fracturing additives.

[265] New York Dept. of Envtl. Conservation, *supra* note xx, at 7.11.5 (noting that "[m]unicipalities may require trucks transporting hazardous materials to travel on designated routes, in accordance with a road use agreement").

general regulations provide little useful guidance to operators, they may be important if litigation results from a drilling fracturing operation. They may potentially allow plaintiffs to argue that a fracturing operator who caused pollution acted negligently "per se" because he or she violated a statute, for example.[266]

Figure 2. Examples of general prohibitions on water pollution

Ohio: "All persons engaged in any phase of operation of any well or wells shall conduct such operation or operations in a manner which will not contaminate or pollute the surface of the land, or water on the surface or in the subsurface." Ohio Admin. Code § 1501:9-1-07 (West 2011).

Oklahoma: "In the completion of an oil, gas, injection, disposal, or service well, where acidizing or fracture processes are used, no oil, gas, or deleterious substances shall be permitted to pollute any surface and subsurface fresh water." Ok. Admin. Code § 165:10-3-10 (West 2011).

West Virginia: "Before commencing to drill any well for oil and gas, the well owner or operator shall make proper and adequate provision to prevent surface and underground water pollution." W. Va. Code State R. § 35-4-16.5 (West 2011).

Beyond general prohibitions on water pollution, which may have little effect, states also have implemented more specific constraints on the fracturing process, which should serve as models for the many states that have not yet acknowledged the additional risks that fracturing creates, including increased pressure on casing and the potential for blowouts and spills. Examples of general regulations and specific constraints on the fracturing process are described in Figure 3.

[266] *See, e.g.*, Potts v. Fidelity Fruit & Produce Co., 165 Ga.App. 546, 546 (1983) (describing how, in cases in which a plaintiff cannot establish "ordinary negligence," she may be able to establish nuisance per se if she can demonstrate that the allegedly negligent party violated a statute, that she plaintiff is in the class of persons intended to be protected by the statute, and that the statute was intended to guard against the harm that she complains of"). The authors located this case in David W. Robertson et al., Cases and Materials on Torts 106 (3d. ed. 2004).

Figure 3. Constraints on the Hydraulic Fracturing Process

Arkansas: Operators must monitor casing annuli that could show "potential loss of well bore integrity" during fracturing and "establish methods to timely relieve any excessive pressures." Ark. Oil & Gas Comm'n Rule B-19 (2011).

Montana: "New and existing wells which will be stimulated by hydraulic fracturing must demonstrate suitable and safe mechanical configuration for the stimulation treatment proposed." Mont. Admin. Code § 36.22.1106 (2011).

North Dakota: "If perforating, fracturing, or chemical treating results in irreparable damage which threatens the mechanical integrity of the well, the commission may require the operator to plug the well." N.D. Admin. Code 43-02-03-27 (2011). Many additional requirements proposed in 43-02-03-21 (pressure relief valves, etc.).

Oklahoma: Operators are prohibited from polluting surface or subsurface freshwater when fracturing used. Okl. Admin. Code § 165:10-3-10 (2011).

Wyoming: "Blending equipment used in fracturing operations" that use flammable and/or combustible liquid must be grounded; valves in discharge lines must be checked to ensure that they are open before pumping; all acidizing, fracturing, and hot oil trucks must be at least 75 feet from the well bore. All spilled acid must be covered or properly disposed of. Wy. Admin. Code OIL Ch. 8, § 6 (2011).

Figure 4 shows examples of regulation of fracturing fluid and flowback containment and transport.

A final recent regulatory development that is specific to fracturing does not aim to constrain or control the fracturing process. Rather, it ensures that officials responding to potential problems, such as spills or human exposure to fracturing chemicals, are aware of the types of chemicals involved. At the federal level, the Emergency Planning and Community-Right-To-Know Act and the Occupational Safety and Health Act already require that operators keep material safety data sheets (MSDS) for certain hazardous chemicals stored on site in threshold quantities.[267] State regulations are slowly supplementing these basic federal laws. In some cases, states have begun

Figure 4. Regulation of fracturing fluid and flowback containment and transport: examples

[267] See Emergency Planning and Community Right-to-Know Act of 1986 §§ 312–313, 42 U.S.C. §§ 11021–11022 (2006); Community Right-to-Know Reporting Requirements, 55 Fed. Reg. 30,632–37 (July 26, 1990).

Flowback transport in Arkansas: The state requires a permit (renewed annually); a $100 fee/transportation tank; name, address, and business and emergency telephone numbers; a description of type and number of tanks; and Entity Organizational Report; and a visible permit sticker. Ark. Oil & Gas Comm'n Rule B-17(g); Rule E-3(d) (2011). Records must be maintained for three years. *Id*. at E-3(h). All tanks must be leak free, and the state places limits on the location to which fluids may be transported. *Id*. at E-3(i).

Colorado hazardous material containers: Containers to treat, store, and "otherwise handle" hazardous material that must be labeled as required by DOT's Hazardous Materials Regulations shall retain labels until the container is "sufficiently cleaned of residue and purged of vapors to remove any potential hazards." Col. Oil & Gas Conservation Comm'n Rule 210d (2011).

to require disclosure of all fracturing chemicals—not just those required to have MSDS under EPCRA or the OSHAct—to agency officials and/or the general public.

As shown in Table 7 below, Colorado, for example, requires operators with more than 500 pounds of hazardous chemicals stored on site during a quarter to maintain a chemical inventory of those chemicals in an accessible format. Colorado also has proposed new disclosure regulations in COGCC Rule 205A, which would require operators to disclose on FracFocus, within 60 to 130 days of completing a hydraulic fracturing treatment, "each hydraulic fracturing additive used in the hydraulic fracturing fluid," the trade name and vendor, a description of the additive function, the CAS number for "each chemical intentionally added to the base fluid," and the maximum concentration (in percent by mass) of these chemicals," as well as water volumes.[268] Louisiana has proposed to require operators to report "the types and volumes of the

Hydraulic Fracturing Fluid . . . used during the Hydraulic Fracture Stimulation Operation," "a list of all additives used" and the "specific trade name" of each additive, and "[t]he maximum ingredient concentration within the additive." Operators in Louisiana also would be required to disclose all chemicals that they have used that are included in OSHA's hazard communication

[268] Colorado Oil & Gas Conservation Comm'n, Revisions and Additions to Rules and Regulations, Rule 205A, *available at* http://cogcc.state.co.us/RR_HF2011/ProposedAmendmentsToRules.pdf.

regulations, which provide that "[c]hemical manufacturers and importers shall obtain or develop a material safety data sheet for each hazardous chemical they produce or import."[269] Texas recently enacted statutory disclosure requirements similar to Louisiana's proposed rules, but it would not require that "the ingredients be identified based on the additive in which they are found or that the concentration of such ingredients be provided."[270] Railroad Commission disclosure rules (effective Jan. 2, 2012) further specify how operators must publicly disclose the chemicals used in fracturing.[271] Several states require disclosure of chemicals used at each site through a new chemical disclosure website called "Frac Focus" developed by the Ground Water Protection Council and industry (or offer this as one disclosure option). These and other examples of disclosure laws—many of which emerged in 2011—are included in Table 7 below.

Chemical disclosure, although only a procedural regulation that does not directly prevent the risk of chemical spills or water contamination, is an important component of state regulation. Indeed, the State Review of Oil and Natural Gas Environmental Regulations provides, "State programs should contain mechanisms for disclosure of information on chemical constituents used in fracturing fluids to the state in the event of an investigation or to medical personnel in the event of a medical emergency."[272] Disclosure *prior* to these events would better protect human health and the environment. Pre-incident disclosure—prior to conducting a fracturing operation—would allow state and federal agencies to better and more quickly respond to accidental spills and more effectively clean them up. Health officials also could more quickly identify the chemicals to which a patient was exposed. Finally, up-front disclosure would improve regulation. If scientists, agency officials, and the public are aware of the chemicals used at each drilling and fracturing site, this would better inform the development of new regulations that, for example, control fracturing chemical and flowback transport, require enhanced spill prevention and emergency

[269] 29 C.F.R. § 1910.1200.

[270] HB 3328 (2011) (enacted).

[271] Railroad Comm'n of Tex., Proposed Texas Admin. Code § 3.29: Hydraulic Fracturing Chemical Disclosure Requirements (HB 3328, 2011), adoption approved at conference Dec. 13, 2011, effective date of adoption Jan. 2, 2012, *available at* http://www.rrc.state.tx.us/rules/signed-adopt-3-29-Dec13-2011.PDF.

[272] STRONGER, Hydraulic Fracturing Guidelines, *supra* note 133, at X.2.2.

response plans, and constrain the methods of disposing of and transporting flowback water, which contains fracturing chemicals in diluted form.

Another means of lowering the risk of harm to the environment and human health from fracturing is to require fracturing operators to notify agencies prior to conducting a fracturing job and to mandate that someone from the agency supervise the operation. The State Review of Oil and Natural Gas Environmental Regulations, for example, suggests, "The regulatory agency should require appropriate notification prior to, and reporting after completion of, hydraulic fracturing activities."[273] Many states require this notification,[274] although this regulatory element is not included in Table 7. Tables 7a to 7c show the chemical disclosure provisions in the regulation of the fracturing process with respect to the following:

- Chemical that must be disclosed
- Trade secret protection allowed
- Direct public access to disclosed chemicals

[273] *Id*.

[274] *See, e.g.*, STRONGER, Louisiana Hydraulic Fracturing State Review 13 , Mar. 2011, *available at* http://www.strongerinc.org/documents/Final%20Louisiana%20HF%20Review%203-2011.pdf (observing that "the district manager must be notified at least 12 hours prior to the initiation of any work under the Work Permit" (which covers fracturing); STRONGER, Ohio Hydraulic Fracturing State Review 12 (Jan. 2011), *available at* http://www.dnr.state.oh.us/Portals/11/oil/pdf/stronger_review11.pdf ("Operators are required to notify [Ohio's oil and gas agency] at least 24 hours before the initiation of hydraulic fracturing.").

Table 7a. Regulation of the fracturing process: Chemical disclosure – chemical that must be disclosed

AR	All "specific additives" used in fracturing: actual rate or concentration and percent "by volume of the total "Hydraulic Fracturing Fluids and Additives." AOGC Rule 19(k) (2010). Also must report chemicals anticipated to be used. *Id*.
CO	All chemical products used downhole or stored in "an amount exceeding five hundred (500) pounds during any quarterly reporting period." 2 CCR 404-1 Rule 205 (2011); 2 CCR 404-1 Rule 100 (2011). Proposed: all chemicals and additives and their concentration. COGCC Rule 205A (proposed 2011).
KY	*Search did not locate statute, regulation, or policy addressing this issue.*
LA	"[A]ll constituents added downhole in conjunction with drilling and workover operations." LAC 33:IX.708 (2011). Proposed: types and volumes of fluids used, all additives and specific trade names, maximum ingred. Concentration. LAC 43:XIX.118 (2011)[275]
MD	Material and quantity of materials used for well stimulation and treatment;[276] "drilling additives" and their toxicity.[277]
MI	Copies of MSDS for all fracturing additives used, volumes used.[278]
MT	Stimulation fluid by additive type (such as acid), chemical ingredient name and CAS number for "each ingredient of the additive used, "rate or concentration of each additive." MT ADC 36.22.1015 (2011 unofficial final rule)
NM	Proposed: FracFocus form submitted to Oil and Gas Commission or hydraulic fracturing disclosure form submitted to Oil and Gas Commission[279] (ingredients, purpose, CAS number, max. ingredient concentration). Proposed New Mexico Code R. 19.15.3.11 (2011) revisions, *available at* http://www.emnrd.state.nm.us/ocd/documents/201111-2OCDModifications.pdf
NY	MSDS for "every additive product proposed for use" and "anticipated volume of each produce proposed" provided to NY DEC; "materials and volumes of materials used" on completion report. R SGEIS 8.2.1.1 (2011)
ND	Proposed: Trade name, ingredients, CAS number, maximum ingredient concentration in additive, maximum ingredient concentration in fracturing fluid. NDAC 43-02-03-27.1 (2011)[280]
OH	Invoice. "If applicable, the type and volume of fluid used to stimulate the reservoir of the well." SB 165

[275] For proposed Louisiana Admin. Code 43:XIX.118, *see* http://dnr.louisiana.gov/index.cfm?md=calendar&tmp=detail&eid=110.

[276] Maryland Department of the Environment, Oil/Gas Well Completion Report, Form No. MDE/LMA/PER.019 at 3, Nov. 1, 2008, available at http://www.mde.state.md.us/assets/document/permit/MDE-LMA-PER019-oilgas.PDF.

[277] Maryland Department of the Environment, Application for Gas Exploration and Production, Section 4. Marcellus Shale Wells/ Hydro Fracturing Addendum, Form No. MDE/LMA/PER.045 at 5, Nov. 1, 2008, available at http://www.mde.state.md.us/assets/document/permit/MDE-LMA-PER045.pdf.

[278] *See supra* note xx (Michigan Dep't of Envtl. Quality Instruction 1-2011).

[279] Susan Montoya Bryan, N.M. Oil and Gas Group Proposes Fracking Rule, Santa Fe New Mexican, Aug. 9, 2011, http://www.santafenewmexican.com/localnews/N-M--oil-and-gas-group-proposes-fracking-rule.

[280] For proposed rule, see https://www.dmr.nd.gov/oilgas/rules2012changes.pdf.

OK Volumes of frac fluid and proppant used[281]

PA "Chemicals or additives utilized," including MSDS, "toxicological data, and waste chemical characteristics." Report "approximate quantities of each material and the method of storage."[282]

TX Each chemical ingredient required to be reported under the OSHAct *and* "all other chemical ingredients" used in hydraulic fracturing treatment. HB 3328 (2011) (enacted). *See also* RRC rules effective Jan. 2, 2012.[283]

WV Additives used. W. Va. Code 22-6-2 (2011) (requiring completion report)

WY Stimulation fluid by additive type, chemical compound name and CAS number, proposed rate and concentration of each additive to Wyoming OGCC. WY ADC OIL GEN Ch. 3 s 45(d)

[281] STRONGER Oklahoma report, *supra* note xx, at 5.

[282] Guidelines for a Preparedness, Prevention and Contingency (PPC) Plan for Oil and Gas Development at 3, *available at* http://www.elibrary.dep.state.pa.us/dsweb/Get/Version-48243/chap4.pdf.

[283] *See supra* note 271.

Table 7b. Regulation of the fracturing process: Chemical disclosure – trade secret protection allowed

AR	Yes, with exception for "health care professional, doctor, or nurse" AOGC Rule 19(k) (2010)
CO	Yes, with exception of "written statement of necessity" from COGCC director indicating need for chemical information. COGCC Rule 205d
KY	*Search did not locate statute, regulation, or policy addressing this issue.*
LA	Yes, with exception of disclosure "required by state or federal law to be provided to a health care professional, a doctor, or a nurse." LAC 43:XIX.118 (2011)
MD	No trade secret protection allowance indicated on completion report.
MI	*Search did not locate statute, regulation, or policy addressing this issue.*
MT	Yes, with exception of "medical emergency," written statement from health professional, or MT ADC 36.22.1016 (2011 unofficial final rule)
NM	Presumably yes because FracFocus allows trade secret protection, and proposed rules may be satisfied through FracFocus form disclosure.
NY	Yes, with exception of any information "necessary to ensure that environmental protection and public health and safe drinking water objectives are met." R SGEIS 8.2.1.1 (2011)
ND	Yes, with exception for "health care professionals, emergency responders, and state, federal, or tribal environmental or public health regulators" if agency determines disclosure necessary to "protect the public's health, safety, and welfare." NDAC 43-02-03-27.1 (2011)
OH	*Search did not locate statute, regulation, or policy addressing this issue.*
OK	*Search did not locate statute, regulation, or policy addressing this issue.*
PA	No[284]
TX	Yes, but surface owners, adjoining landowners, and state agencies may challenge, and includes a health professional and emergency responder exception. H.B. 3328 (2011) (enacted)
WV	Yes (likely). W. Va. Code 22-6-2 (2011) allows trade secret status for certain information reported.
WY	Yes. WY ADC OIL GEN Ch. 3 s 45(f)

[284] State Review of Oil & Natural Gas Envtl. Regulations, Pennsylvania Hydraulic Fracturing State Review 33, Sept. 2010, *available at* http://www.strongerinc.org/documents/PA%20HF%20Review%20Print%20Version.pdf. "No confidential hydraulic fracturing [information] is currently submitted to DEP. In the event that CBI is submitted, Pennsylvania's Right to Know Law contains provisions to protect this information."

Table 7c. Regulation of the fracturing process: Chemical disclosure – direct public access to disclosed chemicals[285]

AR	Unclear—disclosure is to Director and permit holder. AOGC Rule B-19 (2011)
CO	Unclear—disclosure is to COGCC director and/or Colorado Department of Public Health & Envt. Director of Envtl. Programs. COGCC Rule 205c
KY	*Search did not locate statute, regulation, or policy addressing this issue.*
LA	Yes (FracFocus), or to DNR. http://dnr.louisiana.gov/index.cfm?md=newsroom&tmp=detail&aid=894
MD	Unclear. Completion report is submitted to the Maryland Department of the Environment.
MI	*Search did not locate statute, regulation, or policy addressing this issue.*
MT	Public access possible. Operator must either submit job log, final treatment report, or other document to agency *or* on FracFocus website. MT ADC 36.22.1015 (2011 unofficial final rule)
NM	Proposed: not clear. Operators must either submit FracFocus form or another hydraulic fracturing form to the Oil and Gas Commission. 19.15.3.11 (2011 proposed amendments).
NY	Yes—public will have access to all MSDS on an "individual well basis" on the DEC website. R SGEIS 8.2.1.1 (2011)
ND	Proposed: Yes. NDAC 43-02-03-27.1[286] (2011)
OH	Unclear (disclosure to agency).
OK	Unclear (disclosure to agency).
PA	Unclear (disclosure to agency).
TX	Yes. H.B. 3328 (2011) (enacted)
WV	Unclear (disclosure to agency).
WY	Likely yes.[287]

[285] Note that even in states that only require disclosure of chemicals to agencies, members of the public could potentially obtain chemical data from the agency under the state's public records law.

[286] For proposed rule, see https://www.dmr.nd.gov/oilgas/rules2012changes.pdf.

[287] Rebecca Torrellas, Wyoming Forces Frac Fluid Disclosure, E&P, Sept. 2, 2010, at http://www.epmag.com/2010/September/item66859.php (on file with the *Columbia Law Review*) (suggesting that there will be public access even though only disclosure to agency is required).

4.9 Preventing and Reporting Spills

As introduced in Section 8, when operators ship chemicals to well pads and transfer these chemicals to water, accidental spills may occur.[288] Spills also may occur at other stages of the drilling and fracturing process. Diesel fuel may leak from well pad construction and drilling equipment; surface storage pits and tanks may leak or overflow; flowback water, produced water, drilling mud, or other waste may spill when it is transferred from the well to a storage pit or tank; and releases of chemicals also may occur during the injection of fracturing fluid into the well—during a well blowout, for example.[289] Indeed, depending on the contents of the material spilled, a small amount could contaminate soil or water.[290] Regulations are therefore needed to prevent spills, contain them when they occur, and to ensure proper reporting and cleanup. Under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), companies must report spills of hazardous substances of a threshold quantity and,[291] if contamination has occurred, may be liable for the cost of cleanup.[292] State regulations are needed, however, to prevent spills and ensure fast response and cleanup—and remediation, where needed. The State Review of Oil and Natural Gas Regulations has noted the importance of preventing spills, suggesting in its hydraulic fracturing guidelines that wells should meet the general oil and gas STRONGER guidelines for "contingency planning and spill risk measures."[293] The guidelines, in turn, provide that each state "should develop and adopt a state contingency plan for responding to spills and releases," which should "define the volume of a spill or release . . . which triggers implementation of the plan, . . . the time in which notification

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[288] N.Y. State Dep't of Envtl. Conservation, Rev. SGEIS, *supra* note xx, at xx (spills during transport).

[289] *Id*. at xx (other spills). *See also supra* note xx (describing a "blowout" during fracturing, which sent chemicals to a nearby creek).

[290] *See, e.g.*, Dancy, *supra* note 39, at 13 ("The high TDS concentration of most produced waters can result in a relatively small amount of produced water contaminating a large fresh water aquifer or surface reservoir").

[291] 42 U.S.C. § 9603 (2011) (requiring notification of the National Response Center for releases of hazardous substances in certain quantities); 42 U.S.C. § 9602 (requiring the EPA to establish reportable quantities); 40 C.F.R. § 302.4, Table 302.4 (2010) (establishing threshold quantities).

[292] 42 U.S.C. § 9607 (2011).

[293] STRONGER, Hydraulic Fracturing, *supra* note xx, at X.2.1.

(over)

and subsequent clean—up should occur, and guidance or criteria relating to final remedial verification provisions."[294]

Most states require operators to maintain some form of spill prevention and control plan for unanticipated surface chemical spills, as shown in Table 7. These plans differ substantially, however, in terms of the times by which operators must report spills and the threshold quantities of spills that trigger reporting and/or clean-up requirements. To varying degrees, states also require structural spill prevention measures, including secondary containment, such as dikes, around storage tanks or pits and beneath chemical mixing and tank and/or pit filling operations.[295] These secondary containment structures are intended to capture any spills that occur; some states also require that the structures be maintained so as to effectively trap spills. Some require, for example, that the secondary containment structures remain reasonably free of vegetation and have adequate freeboard—meaning a structure wall (dry space above any liquids in the containment structure) adequate to prevent overflow. Further, some states have hazardous clean-up laws that apply to certain chemical spills in addition to the federal CERCLA. Pennsylvania's Hazardous Site Cleanup Act (HSCA), for example, requires the Department of Environmental Protection to investigate a "release or substantial threat of release of a contaminant which presents a substantial danger to the public health or safety or the environment" or a "release or threat of release of a hazardous substance."[296] The Department must then notify the operator or person responsible and allow that operator or person to respond. The Department itself may respond and implement remedial or removal actions "which . . . [it] deems necessary or appropriate to protect the public health, safety or welfare of the environment."[297] The Department

[294] STRONGER Criteria, *supra* note xx, at 4.2.1.1.

[295] *See, e.g.*, COGCC Rule 604(a)(4) ("Berms or other secondary containment devices shall be constructed around crude oil, condensate, and produced water tanks to provide secondary containment for the largest single tank and sufficient freeboard to contain precipitation.").

[296] HSCA § 501.

[297] HSCA § 501.

may order the responsible person to respond to the release, and the responsible person must cover the cost of this response.[298]

Finally, some states have recently updated their laws to address potential spills from drilling and hydraulic fracturing and to recognize the higher risk of spills that accompanies the addition of new chemicals to the fracturing process. For example, Arkansas added an Exploration and Production Fluid Gathering, Handling, and Transportation Rule in 2009, for example, and this rule applies to fracturing fluids.[299] Tables 8a to 8c explore state regulatory approaches to spill prevention, containment, and cleanup by providing examples of state requirements for spill control, spill reporting, and cleanup/remediation.

In light of the variation in requirements shown in Table 8, states should consider updating their spill prevention and contingency plans to recognize that fracturing adds new chemicals to the oil and gas development process. Some of these chemicals pose a risk even in small quantities; threshold quantities in reporting and clean-up requirements therefore may need to be updated. New York has proposed, and all states should, consider additional structural controls to contain spills of fracturing fluid—particularly when undiluted fluid is transferred to water on site. All states, for example, should consider requiring secondary containment structures under fracturing fluid transfer stations.

[298] HSCA § 505.

[299] A.O.G.C. Rule E-3 (at the end of the rule, explaining that the rule was new in January 2009); A.O.G.C. Rule B-19(g)(6) ("The transfer of Frac Flow-Back Fluids via tank truck shall be in accordance with General Rule E-3.").

Table 8a. Regulation of spills: prevention, control, clean-up, and reporting of spills: Spill prevention and control

AR	Crude oil tank batteries and tanks w/ produced fluids must be surrounded by containment dikes or other containment structures; reservoir in dike must be kept free of excessive vegetation, stormwater, etc. AOGC Rule B-6 (2011)
CO	Emergency spill response programs required in buffer zones around water supplies
	COGCC Rule 317B. Berms or other secondary containment devices around condensate and produced water tanks, must be inspected at regular intervals, have sufficient freeboard COGCC Rule 604
KY	Spill prevention and countermeasures plan only when required for oil pollution prevention by 40 C.F.R. § 112. 401 Ky. Admin. Reg. 5:090 Section 13 (2011)
LA	Spill prevention and control plan. LAC 33: IX.905 (2011)
	Produced water pits "shall be protected from surface waters by levees or walls and by drainage ditches," no siphons or openings shall allow contamination. LAC 43:XIX.307 (2011).[300]
MD	Spill prevention, control, and countermeasures plan.[301] Dikes for pits must be compacted, free of debris, maintained w/ slope that preserves structural integrity. COMAR 26.19.01.10
MI	Pollution incident prevention plan if threshold quantity of chemicals.
	MICH. ADMIN. CODE R 324.2006 (2011). All wellheads and pumpjacks must have secondary containment, must keep dikes free of debris MICH. ADMIN. CODE R 324.1002 (2011)
MT	Must control spills of oil, water, or produced water w/ more than 15,000 ppm TDS.
NM	Secondary containment for large tanks and small tanks w/in 500 ft. of water resources; troughs, drip pads, pans beneath tank fill-port.[302]
NY	State Pollution Discharge Elimination System (SPDES) permit required for both site construction and surface activities associated with high-volume hydraulic fracturing; will include best management practices for spill prevention, which include, for example, locating all additive containers and transport, mixing, and pumping equipment w/in secondary containment and use of drip pans or pads when fracturing fluids are transferred. SGEIS 7.1.2
ND	*Search did not locate statute, regulation, or policy addressing this issue.*
OH	Dike or pit for spill prevention and control; reservoir in dike or pit "must be kept reasonably free of brine & other waste substance." ORC 1509.22(c) (2011)
OK	*Search did not locate statute, regulation, or policy addressing this issue.*

[300] Facilities "shall be equipped with pollution containment devices that under normal operating conditions prevent unauthorized discharges.

All drains from diked areas must have control valves. In wetlands and open waters, if cannot build dike, must use impervious deck w/ curbs, gutters, and/or sumps to retain spills.

La. Admin. Code 33:IX.708(C)(1)(b) (2011).

[301] Md. Dep't of the Env't, Application for Gas Exploration and Production 12.

[302] New York Dep't of Envtl. Conservation, Rev. SGEIS, Proposed Supplementary Permit Conditions for High-Volume Fracturing Operations.

PA Address method of containment for spilled or lost materials and equipment avail. for spill clean-up in disposal plan, also must prepare a Preparedness, Prevention, Contingency (PPC) plan with specific spill control and prevention measures, including secondary containment.

TX *Search did not locate statute, regulation, or policy addressing this issue.*

WV "[C]onfine all materials leaked or spilled as a result of drilling operations to the drilling site." W. Va. CSR 35-4-16 (2011)

WY *Search did not locate statute, regulation, or policy addressing this issue.*

Table 8b. Regulation of spills: prevention, control, clean-up, and reporting of spills: Spill reporting

AR	Report any spill w/in 24 hours. AOGC Rule 19-B (2010). *See also* AOGC Rules B-26, B-24 (2010) (spills from containment dikes).
CO	In buffer zone, notify "affected or potentially affected Public Water System(s) immediately" and report to Comm'n, hotline. COGCC Rule 317B. All spills and releases of more than 5 bbls. E&P waste or spills of any size that could threaten waters must be reported to Comm'n. 2 CCR 404-1 Rules 337, 906(b) (2011); CRS 25-8-601(2) (2011)
KY	Report of spill, including spill of produced water, shall be "made by the most rapid means of communication available." 401 KAR 5:090 (2011); 401 KAR 5:015 (2011)
LA	Immediate notification of hotline for any unauthorized discharge that causes emergency LAC 33:I.3915 (2011); for unauthorized discharge of reportable qty.,[303] notify by telephone w/in 24 hrs. LAC 33:I.3917, 3923 (2011). If unauthorized discharge contaminates groundwater, notify Single Point of Contact w/in 7 days. LAC 33:I.3919 (2011)
MD	Report "no later than 2 hours after detection." COMAR 26.19.01.02 (2011)
MI	"[P]romptly report" all spills; report w/in 8 hours spills of "42 gallons or more of brine, crude oil, or oil and gas field waste." MICH. ADMIN. CODE R 324.1008 (2011)
MT	Immediately report by telephone and written report w/in 5 working days of "spill, leak, or release of more than 50 barrels of oil or water containing more than 15,000 parts per million (ppm) total dissolved solids (TDS)" and any qty of above that enters groundwater or surface water. MONT. ADMIN. R. 36.22.1103 (2011)
NM	Immediate verbal notice for unauthorized release (excluding gases) > 25 BBLs or gases > 500 MCF to district office and written notice w/in 15 days; written notice w/in 15 days for >5 BBLs, < 25 BBLs non-gas or >50 mcf, <500 mcf gas. NM ADC 19.15.29.9 and 10 (2011)
NY	NY: Verbal notification of any spill w/in 2 hrs. of discovery. R SGEIS 7.1.6 DRBC: Immediately report release or threatened release of any "substance, pollutant, or contaminant". Proposed Regs. 7.5(h)(1)(vi) (2011)
ND	Verbally notify director w/in 24 hrs. of any leak or release of fluid, "written report within ten days after cleanup of the incident." Notification of surface owner also required. N.D. Admin. Code 43-02-03-31 (2011)
OH	*Search did not locate statute, regulation, or policy addressing this issue.*
OK	Must report w/in 24 hrs. of discovery any discharge to waters or discharge >10 bbls. to surface. OAC 165: 10-7-5 (2011)
PA	DRBC: Immediately report release or threatened release of any "substance, pollutant, or contaminant" Proposed Regs. 7.5(h)(1)(vi) (2011); *see also* Preparedness, Prevention, and Contingency Plan requirements;[304] 25 Pa. Code § 79.15 (oil and gas spills)
TX	*Search did not locate statute, regulation, or policy addressing this issue.*

[303] See Louisiana Admin. Code § 33:I.3931 (2011) for list of reportable quantities.

[304] The PPC must designate a company representative responsible for spill reporting and "contain a list of the agencies to be notified" if an incident occurs. Penn. Dep't. of Envtl. Protection, Oil and Gas Management Practices, at 4, *available at* http://www.elibrary.dep.state.pa.us/dsweb/Get/Version-48243/chap4.pdf.

WV Must report discharge of more than 1,000 U.S. gallons w/in 12-month period. W. Va. CSR § 35-1-9 (2011); immediate notification of any discharge W. Va. CSR § 47-11-2 (2011).

WY Must verbally report contained spills of >10 barrels (420 gallons) "No later than the next business day following discovery of incident; for contained spills of 1 barrel (42 gallons) or more file written report w/in 15 days. All unauthorized releases must be reported verbally no later than next business day and in writing w/in 15 working days. WY ADC OIL GEN Ch. 4 s 3 (2011)

Table 8c. Regulation of spills: prevention, control, clean-up, and reporting of spills: Spill cleanup/remediation

AR	Immediately contain spill, commence remediation efforts "as soon as practical" A.O.G.C. Rule 19-B (2010); has specific remediation requirements for spills of crude oil and produced water. A.O.G.C. Rule B-34(c)-(d)(2010)
CO	In buffer zones, "immediately implement" emergency spill response program COGCC Rule 317B; control and immediately contain all E&P waste spills to protect envt., Director may require "Site Investigation and Remediation Workplan." 2 CCR 404-1 Rule 906 (2011). Specific soil remediation based on sodium absorption ratio.
KY	*Search did not locate statute, regulation, or policy addressing this issue.*
LA	For any unauthorized discharge of oil, produced water, other waste, "immediately" initiate "remedial response"; if immediate clean-up not appropriate, alternative remedial plan. La. Admin. Code 33:IX.708(C)(1)(b) (2011)
MD	*Search did not locate statute, regulation, or policy addressing this issue.*
MI	*Search did not locate statute, regulation, or policy addressing this issue.*
MT	"Promptly control and clean up any leak, spill, escape, or discharge, regardless of the amount of oil, produced water, water containing more than 15,000 ppm TDS, or gas involved." ARM 36.22.1104.
NM	*Search did not locate statute, regulation, or policy addressing this issue.*
NY	Stormwater BMPs would include "[p]rocedures for immediately stopping the source of the spill and containing the liquid until cleanup is complete"; remediation BMPs also proposed. R SGEIS 7.1.2.1, 7.1.3.1.
ND	*Search did not locate statute, regulation, or policy addressing this issue.*
OH	*Search did not locate statute, regulation, or policy addressing this issue.*
OK	Unpermitted discharge from pit: "sufficient measures to stop or control the loss"; clean up pursuant to instructions. OAC 165:10-7-16
PA	If spill occurs during transportation, transporter "must immediately clean up the waste" and take other action to prevent threats to human health, safety, welfare, environment; O&G operators in PPC must list clean-up equipment that will be on site, may need to bring in "outside cleanup contractors."[305]
TX	*Search did not locate statute, regulation, or policy addressing this issue.*
WV	*Search did not locate statute, regulation, or policy addressing this issue.*
WY	Soil cleanup levels to maximum concentration of total petroleum hydrocarbons determined by oil contaminated soil remediation ranking system of API if aquifer, surface water, other resources affected. If these resources will not be affected, remove harmful properties of waste, reduce or eliminate leachate mobility, remove and treat contaminated soil to "acceptable level."[306]

[305] Penn. Dep't. of Envtl. Protection, Oil and Gas Management Practices, at 4, 85, *available at* http://www.elibrary.dep.state.pa.us/dsweb/Get/Version-48243/chap4.pdf.

[306] Wyoming Oil and Gas Conservation Commission, Guideline for Spill Cleanup, Dec. 10, 2002, http://wogcc.state.wy.us/craig/spill.htm.

4.10 Testing and Replacing Water Supplies

As discussed in Sections 6 through 9, hydraulic fracturing adds several new stages to the development process of an oil or gas well. Additional quantities of water must be withdrawn, new chemicals must be transported to and transferred on site, and the process of injecting the water and chemicals down the well increase pressure on the casing, thus requiring better casing, cementing, and blowout prevention measures. Many of these risks also exist for traditional oil and gas wells, and at the non-fracturing stages of the development process of a shale well. Spills may occur during well pad construction and drilling, for example, and casing may give out during drilling, rather than fracturing. These risks are heightened by the addition of fracturing to the development process, however. Furthermore, the fact that fracturing allows the development of thousands of new wells means that more wells are drilled, thus increasing the risks that arise at the site development and drilling stages.[307]

As Professor Eastin's paper discusses, despite the many stages of the shale gas development process, much of the media attention to shale gas development risks has focused on fracturing alone, and particularly on the concern that fracturing will contaminate underground water supplies. Regardless of the level of risk of underground contamination, it is essential that operators conduct baseline testing of water supplies around a well drilling and fracturing sites to establish the contaminants that already exist, to provide better data for scientific research on causal mechanisms of contamination moving forward, and to provide landowners with proof when water contamination is caused by drilling or fracturing and water supply replacement is needed.

The lack of baseline testing and post-drilling and fracturing data amplifies the difficulty of accurately identifying the risk to underground water supplies posed by drilling and fracturing. States should update their regulations to require one entity—either the operator, the landowner, or a state agency—to conduct baseline and post-drilling and fracturing testing using approved

[307] A forthcoming companion piece describes this concept through the lens of mobile air pollution. One car on the road poses few risks; several hundred thousand cars substantially increase air pollution and other problems. Hannah Wiseman, Draft, *Reframing Risk and Response in Fracturing Policy* (2012).

testing procedures and to submit this data to a centralized state database. Considerations about who should shoulder the cost of testing should take into account which parties have the most knowledge of appropriate testing procedures, can afford the testing, and will ensure that testing is conducted consistently and accurately.[308]

A limited number of states require or allow operators to test nearby water wells prior to and/or after drilling and fracturing a well. Colorado, which focuses on the integrity of public drinking water supplies, requires testing of nearby surface waters and notification of municipalities if contamination is located. In addition to requiring baseline testing—and, in a limited number of cases—follow-up testing, at least one state (Pennsylvania) also regulates liability for water contamination, establishing a rebuttable presumption that the well operator caused the contamination within 1,000 feet of the well and requiring the operator to replace water supplies.[309] Pennsylvania also recently revised its regulations to expand protections of water supplies near gas wells. In updating both its well casing and water replacement requirements, Pennsylvania's Department of Environmental Protection explained:

> Many of the regulations governing well construction and water supply replacement were promulgated in July 1989 and remain largely unchanged. New well drilling and completion practices used to develop Marcellus Shale wells, as well as recent impacts to drinking water supplies by both traditional and Marcellus Shale wells, caused the Department to reevaluate the existing requirements.[310]

Accordingly, the Department substantially expanded the procedures that operators deemed responsible for water contamination must follow in replacing contaminated water supplies. It now requires, for example, that operators ensure that the new supply is as "reliable" and

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[308] This requirement may appear to be too onerous; it will be costly for operators, and some operators may lack access to wells if landowners deny entry. Several states already require this type of baseline testing, however, suggesting that oil and gas development is still moving forward despite an apparently burdensome regulatory requirement. Furthermore, by establishing a rebuttable presumption that water contamination within 1,000 feet of an oil and gas well and discovered within six months of the end of well drilling or completion was caused by the well operator, Pennsylvania has effectively required baseline testing.

[309] 58 P.S. 601.208 (2011).

[310] Proposed Rulemaking, Environmental Quality Board, 40 Pa.B. 3845, July 10, 2010, http://www.pabulletin.com/secure/data/vol40/40-28/1248.html; regulations codified at 25 Pa. Code § 78.83 et seq. (2011).

"permanent" as the previous water supply, and that"[n]ot require excessive maintenance." Operators also must ensure that the property owners have as much control over and access to the water supply as they did prior to contamination. "[P]lumbing, conveyance, pumping or auxiliary equipment and facilities necessary for the surface landowner or water purveyor to utilize the water supply," are among other requirements.[311] Michigan legislators recently proposed but did not enact a similar law that would have presumed operator liability for water contamination and required water replacement. Michigan HB 4736, introduced in June 2011, would have provided:

> If groundwater in the vicinity of a well used for hydraulic fracturing is determined to contain 1 or more hazardous substances that were injected into that well while conducting hydraulic fracturing, there is a rebuttable presumption that the person conducting the hydraulic fracturing is liable . . . for the contamination present in the groundwater.

Tables 9a to 9c offer examples of state regulations addressing baseline water testing and replacement in the event of contamination. The dearth of baseline and post-drill and fracture testing requirements suggests that substantial regulatory updates are needed in this area. Tables 9a and 9b describe requirements for baseline testing and source replacement with respect to testing required or allowed and water supply replacement by operator required.

[311] *Id*. (codified at 25 Pa. Code § 78.51).

Table 9a. Regulation of drinking water sources: Requirements for baseline testing and source replacement – testing required or allowed

AR	*Search did not locate statute, regulation, or policy addressing this issue.*
CO	Collection of baseline surface water data and data from 3 mos. after operation required around public water systems and over certain aquifers.[312] 2 CCR 404-1 Rule 317(b) (2011). Voluntary baseline water well testing results must be disclosed.[313]
KY	*Search did not locate statute, regulation, or policy addressing this issue.*
LA	Ground water monitoring may be required as part of plan for preventing contamination if "any pit . . . is likely to contaminate a groundwater aquifer" or underground source of drinking water. 43 LA ADC Pt. XIX § 309
MD	*Search did not locate statute, regulation, or policy addressing this issue.*
MI	Hydrogeological investigation, including water quality sampling, required. MICH. ADMIN. CODE R 324.1002 (2011)
MT	*Search did not locate statute, regulation, or policy addressing this issue.*
NM	*Search did not locate statute, regulation, or policy addressing this issue.*
NY	Required w/in 1,000 ft. of well pad (or 2,000 ft. if none w/in 1,000 ft.) SGEIS at 1-10 RSGEIS at 1-10[314] DRBC: groundwater and surface water pre-alteration monitoring study report, post-drilling sampling. DRBC Draft Regs. 7.5(h)(2)(i) (2011)
ND	*Search did not locate statute, regulation, or policy addressing this issue.*
OH	Required for all water wells w/in 300 ft. of "proposed well location" in urbanized areas. OH ADC 1501:9-1-02(F) (West 2011)
OK	Required only for "enhanced recovery injection" UIC operations. OAC 165:10-5-5 (2011)
PA	Allowed ("predrilling or prealteration survey of water supplies"). 58 P.S. 601.208 (2011); 25 Pa. ADC 78.52 (2011)
TX	*Search did not locate statute, regulation, or policy addressing this issue.*
WV	Required at request of owner w/in 1,000 feet of well. W. Va. CSR 35-4-19 (2011)
WY	*Search did not locate statute, regulation, or policy addressing this issue.*

[312] Baseline water well testing in Greater Wattenburg Area required for closest water well in Laramie/Fox Hills Aquifer; further testing if complaints 2 CCR 404-1 Rule 318A(e) (2011); ground water samples required "where ground water contamination" suspected or known, impacted soils "are in contact with ground water," or "impacts to soils extend down to high water table" 2 CCR 404-1 Rule 910 (2011).

[313] *See* Colorado Oil and Gas Association Voluntary Baseline Groundwater Sampling Program, http://www.coga.org/index.php/BaselineWaterSampling.

[314] A full description of the proposed water well testing requirements is located in Chapter 7 of the Revised Draft Supplemental Generic Environmental Impact Statement.

Table 9b. Regulation of drinking water sources: Requirements for baseline testing and source replacement -- water supply replacement by operator required

AR	Compensation only for damage to non-water resources (real property, soil, trees, crops, etc.) caused by produced water or crude oil. Ark. Code 15-72-219 (2011)
CO	*Search did not locate statute, regulation, or policy addressing this issue.*
KY	Replacement "where the supply has been substantially disrupted by contamination, diminution, or interruption proximately resulting from the operator's oil or gas operation." KRS 353.597
LA	*Search did not locate statute, regulation, or policy addressing this issue.*
MD	*Search did not locate statute, regulation, or policy addressing this issue.*
MI	Proposed but not implemented: If groundwater "in vicinity" of fractured well has 1 or more hazardous substances used in fractured well, rebuttable presumption of liability."[315]
MT	"The oil and gas developer or operator is responsible for damages to real or personal property caused by oil and gas operations and production." Mont. Admin. R. 82-10-505 (West 2011).
NM	*Search did not locate statute, regulation, or policy addressing this issue.*
NY	Joint investigation by DEC and county health department of complaints about water well contamination during active operation at well pad (or within a year of last hydraulic fracturing) within 2,000 ft. or radius where baseline sampling occurred; if complaint coincides w/ non-routine incident, Dept. may require "immediate corrective action." RSGEIS at 7.1.4.1
ND	*Search did not locate statute, regulation, or policy addressing this issue.*
OH	Replace or compensate if supply "substantially disrupted by contamination . . . proximately resulting from the owner's oil and gas operation." ORC 1509.22 (2011)
OK	*Search did not locate statute, regulation, or policy addressing this issue.*
PA	Replacement supplies of same quality and quantity as previous supply. 25 Pa. Code 78.51 (2011)
TX	*Search did not locate statute, regulation, or policy addressing this issue.*
WV	Must submit groundwater remediation plan "where practical, to reduce the level of contamination over time to support drinking water use." W.Va. CSR 35-4-20 (2011)
WY	*Search did not locate statute, regulation, or policy addressing this issue.*

[315] H.B. 4736 (Mich. June 14, 2011) (not enacted), *available at* http://legislature.mi.gov/documents/2011-2012/billintroduced/House/pdf/2011-HIB-4736.pdf

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4.11 Storing Waste

Waste from drilling and fracturing is typically stored on site in a pit or tank prior to permanent disposal. This waste includes drill cuttings and drilling fluids; produced water, which is released from the formation during the drilling and/or fracturing process; and flowback water (fracturing fluids that flow back up out of the well following fracturing). The pits used to store these wastes have a variety of names, and different state regulations often apply to each pit. A "reserve pit," for example, may contain drilling muds and other drilling wastes, while a completion pit may contain hydraulic fracturing fluids. A state may require a permit for completion pit but not for the reserve pit, or a synthetic liner for one pit but not the other.

States regulate the storage of waste on site in order to prevent pit wastes from contaminating soil or water beneath or surrounding the pit and to avoid other impacts, such as harm to livestock,[316] humans,[317] or migratory birds. Some states require that pits have liners, including synthetic, clay, or other earthen liners, and often that the liners be of a certain thickness. States also typically regulate the amount of "freeboard" required for each pit—meaning the dry space above the waste in the pit necessary to ensure that the pit does not overflow. New Mexico recently revised its "pit rule" to require liners and steel tanks in some cases (effective June 16, 2008);[318] several industry associations have proposed revisions to the pit rule, arguing that the rules should eliminate the requirement for steel tanks in some cases and other requirements.[319] The Commission posted a public hearing on the revisions on December 16, 2011.[320] Other states, through similarly

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[316] *See, e.g.*, West Virginia Department of Environmental Protection, Industry Guidance, Jan. 8, 2010 , http://www.dep.wv.gov/oil-and-gas/GI/Documents/Marcellus%20Guidance%201-8-10%20Final.pdf (requiring all pits to have "lifelines and perimeter fencing").

[317] Oklahoma, for example, requires that "[e]ach frac tank used at the wellsite shall have protective man-ways to prevent persons from accidentally falling into the frac tank."OAC 165:10-3-18 (2011).

[318] N. M. Code R. 19.15.17

[319] Case No. 14784, Application of the New Mexico Oil and Gas Association for Amendment of Certain Provisions of Title 19, Chapter 15 of the New Mexico Administrative Code Concerning Pits, Closed-Loop Systems, Below Grade Tans, Sumps and Other Alternative Methods Related to the Foregoing and Amending Other Rules to Conforming Changes, Statewide, Sept. 30, 2011 *available at* http://www.emnrd.state.nm.us/ocd/documents/Application_000.pdf. The Independent Petroleum Association has proposed similar amendments, available at http://www.emnrd.state.nm.us/ocd/documents/201111-29ApplicationIndependentPetroleumAssociation.pdf.

[320] State of New Mexico, Oil Conservation Commission, Case No. 14784, *available at* http://www.emnrd.state.nm.us/ocd/documents/201112-16NoticeWeb.pdf

protective measures, require "closed-loop" drilling systems, meaning that all drilling and fracturing waste must be stored in tanks, not pits. Colorado, for example, require these systems for drilling close to protected public water supplies, and New York proposes to require closed-loop systems for all Marcellus Shale development that uses large volumes of water ("high-volume" fracturing). Most states described in Table 10, however, allow wastes to be stored in pits. In light of the fact that fracturing has introduced a new, potentially more hazardous waste to the oil and gas development process in the form of flowback water, states that currently do not require pits to be lined should consider doing so. States also should update their regulations to address flowback pits, if they have not yet. Many of the traditional labels for pits do not make clear whether these pits may contain flowback water, thus failing to identify which pit construction and closure methods operators must follow for flowback pits.

Tables 10a to 10c summarize the storage regulations that apply to flowback water, focusing on liner mandates, freeboard requirements, and requirements for pit closure[321] and, omitting—in the interest of brevity—similar regulations that apply to the storage of produced water, drilling muds, and other drilling wastes. The regulations of on-site fracturing waste storage are summarized with respect to the liner and freeboard requirements for flowback water and the timing of pit closure for flowback.

[321] In addition to the timing of pit closure, some states regulate how quickly materials must be removed from pits. New Mexico, for example, requires an operator to remove "any visible or measurable layer of oil" from surface of pit "immediately after cessation" of drilling or workover, remove all free liquids w/in 30 days from release of drilling or workover rig. NM Admin. Code § 19.15.17.12 B. (2011).

Table 10a. Regulation of on-site fracturing waste storage: Flowback water -- liner requirement

AR	Clay (compacted) and 40-mil synthetic liner. AOGC Rule B-17 (2010)
CO	Tank (pitless drilling) for existing O&G operations w/in 300 ft. of public water supply and new operations w/in 301-500 ft. Synthetic liner farther from water supply.[322] 2 CCR 404-1 Rule 904 (2011)[323]
KY	If pit used for longer than thirty days after completion of exploration or drilling, 20-mil synthetic liner 401 Ky. Admin. Reg. 5:090 Section 9(5)(a) (2011)[324]
LA	Natural, soil mixture, and synth. for produced water pits, must be "equiv. of 3 continuous feet of recompacted or natural clay" w/ hydraulic conductivity not > 1 x 10^7 cm/sec."[325] La. Admin. Code 43:XIX.307 (2011)
MD	No liner requirement, but pits must be "impermeable" and "[a]llow no liquid or solid discharge of any kind into the waters of the State." COMAR 26.19.01.10
MI	Appears to require tank.[326] Drilling mud pits must have 20-mil polyvinyl chloride liners. MICH. ADMIN. CODE R 324.407 (2011)
MT	Synthetic impermeable liner for pits containing >15 ppm TDS. No hazardous materials stored in earthen pit or open vessel, may not be located in floodplain. ARM 36.22.1207 (2011)
NM	Temp. pits: Geomemb. 20-mil string reinforced LLDPE or equiv. NM ADC 19.15.17 F. (2011). Permanent pits: Geomembr. 30-mil flexible PVC or 60-mil HDPE liner or equiv. 19.15.17 G. (2011)
NY	NY: No pits allowed; water tight steel tanks required. R SGEIS 7.1.3.4 (2011) DRBC: "materials suitable to safely contain the wastewater stored"
ND	Lined and "sufficiently impermeable to provide adequate temporary containment of the oil, water, or fluids." NDCC 43-02- 03-19.3 (2011)
OH	Pits must be "liquid tight." OAC 1501: 9-3-08 (2011)
OK	Synthetic in wellhead protection area, w/in 1 mile of active municipal water well, other sensitive areas.

[322] Synthetic liner of 24-mil. thickness and soil foundation compacted 12 inches for new operations w/in 501- 2,640 ft. and existing operations w/in 301-2,640 ft. Rule 317B, 904; other locations: if pit has certain hydrocarbon or chloride concentrations, see 12" soil and 24-mil liner requirement above. 2 CCR 404-1 Rule 904 (2011).

[323] COGCC Rule 100 makes clear that "drilling pits" include "flowback pits," and Rule 904 requires a twelve-inch compacted soil foundation and a synthetic liner with 24-mil thickness for drilling pits "designed for use with fluids containing hydrocarbon concentrations exceeding 10,000 ppm TPH or chloride concentrations at total well depth exceeding 15,000 ppm."

[324] This liner requirement applies to holding pits, and the definition of "holding pit" is "an earthen excavated depression designed to receive and store produced water at a facility." 401 KAR § 5:090, Section 2(13) (2011). The requirement also applies to "drilling pits" used for more than thirty days "following the completion of exploration and drilling activities." 401 Ky. Admin. Reg. 5:090 Section 10 (2011).Drilling pits include any "earthen excavation for the collection of fluids associated with the drilling, construction, completion, acidizing, or fracturing of an oil or gas well." 401 Ky. Admin. Reg. 5:090 Section 13(7).

[325] I assume here that produced water pits in Louisiana include flowback water. (See pit definitions.)

[326] MICH. ADMIN. CODE R 324.407 (2011) provides that "only the following materials may be placed in a lined pit" and does not include flowback water or completion fluids in the list of acceptable materials.

OAC 10-7-16

PA "Synthetic flexible liner with a coefficient of permeability of no greater than 1 x 10^7 cm/sec." 25 Pa. Code 78.56 (2011)

TX No liner requirement unless RRC requires. 16 TEX. ADMIN. CODE § 3.8(d)(4)[327]

WV Impervious liner req. if soil does not prevent seepage, leakage, overflows

WY Tanks required for non-RCRA exempt wastes and where groundwater is less than 20' below surface. WY ADC OIL GEN Ch. 4 s 1(q), (u) (2011). Synthetic lining for exempt wastes.[328] Liner or tank required for flowback water. WY ADC OIL GEN Ch. 3 s 45 (j) (2011)

[327] This assumes that "completion pit" refers to a pit with flowback water.

[328] For exempt wastes, "lining of pits with reinforced oil grade material, compatible with the waste to be received," required under certain circumstances." *Id*. at (w). Lining always required if tds >10,000 mg/l. *Id*. at (w). "Soil mixture liners, recompacted clay liners, and manufactured liners must be compatible with waste," synthetic 9-12 mil thickness. *Id*.

Table 10b. Regulation of on-site fracturing waste storage: Flowback water: freeboard requirement

AR	2 ft. (flowback for recycling only stored in reserve pit up to 90 days) AOGC Rule B-17
CO	2 ft. COGCC Rule 902(b)
KY	1 ft. 401 Ky. Admin. Reg. 5:090 Section 9(5)(B) (2011)
LA	2 ft. LAC 33:IX.708(C)(1) (2011)
MD	2 ft. COMAR 26.19.01.10(j)
MI	Appears to require tanks,[329] thus no pit freeboard requirement.
MT	3 ft. for earthen pits w/ 15,000 parts ppm TDS in volumes greater than 5 BBL monthly. ARM 36.22.1227 (2011)
NM	2 ft. for temporary pits. NM ADC 19.15.17.12(B) (2011); 3 ft. for permanent. *Id*. at (C); NMADC 19.15.17.7 (2011)[330]
NY	2 ft. NY SGEIS Appendix 10 (2011)
ND	*Search did not locate statute, regulation, or policy addressing this issue.*
OH	"[C]onstructed and maintained so as to prevent escape of saltwater and oil field wastes"; level of saltwater in excavated pits shall not rise above ground level. OH Admin. Code 1501: 9-3-08 (2011)
OK	2 ft. OAC 10-7-16
PA	2 ft. 25 Pa. Code 78.56(a) (2011)
TX	Brine evaporation pits only: 2 ft. 30 TAC § 218.20(c) (2011).
WV	"[A]dequate freeboard to prevent overflow from any pit," and at least 2 ft. W. Va. CSR § 35-4-16 (2011)
WY	Must keep liquids at "level that takes into account extreme precip. events and prevents over-topping and unpermitted discharges." WY ADC OIL GEN Ch. 4 s 1(w)(2011).

[329] MICH. ADMIN. CODE R 324.407 (2011) provides that "only the following materials may be placed in a lined pit" and does not include flowback water or completion fluids in the list of acceptable materials. *See also* MICH. ADMIN. CODE R 324.502 (2011) ("A permittee of a well shall not store or retain oil, brine, or associated oil or gas field waste in earthen reservoirs or open receptacles.").

[330] A permanent pit is a pit "constructed . . . for the duration provided in its permit.

Table 10c. Regulation of on-site fracturing waste storage: Timing of pit closure for flowback

AR	Stored in reserve pit up to 90 days. AOGC Rule B-17(g) (2010)
CO	3 years in high-density areas. 2 CCR 404-1 Rule 902 (2011)
KY	Backfill when pit no longer used for intended purpose.. 401 KY ADC 5:090 s 9(5)(c) (2011)
LA	All pits closed w/in 6 mos. of abandonment. LAC 43:XIX.307 (2011)
MD	*Search did not locate statute, regulation, or policy addressing this issue.*
MI	*Search did not locate statute, regulation, or policy addressing this issue.*
MT	All earthen pits closed w/in 1 yr. after ending drilling. ARM 36.22.1005.
NM	Close newly-built pits w/in 60 days or six months for temp. pits. NM ADC 19.15.17.13 B (2011)
NY	"[f]luids removed [from steel tanks] within 45 days of completing drilling and stimulation operations at last well on pad" RSGEIS 7.1.3.4
ND	Contents removed w/in 72 hrs.; timing for pit closure unclear. NDCC 43-02- 03-19.3 (2011)
OH	14 days after removal of rig. Oh Admin. Code 1501:9-9-03 (2011)
OK	W/in 60 days or six months (if converted reserve/circulation pit) after completion, fracture, workover, or drilling operations cease. OAC 165:10-7(e)(7)
PA	remove or fill the pit w/in 9 months after completion of drilling unless obtained a control, storage, and disposal permit, he/she must [331]
TX	Unclear which pits contain flowback water. Completion/workover pits must be closed w/in 30 days of completion of workover operations and backfilled, compacted w/in 120 days. Reserve and mud circulation pits closed w/in one year of cessation of drilling operations for low chloride, 30 days for high chloride. 16 TAC § 3.8 (d)(3) (2011)
WV	*Search did not locate statute, regulation, or policy addressing this issue.*
WY	Generally, "based on site-specific conditions," but 1 yr. for pits with hazardous materials.[332]

[331] 25 PA. CODE § 78.56 (d) (West 2011).

[332] Closure and remediation required w/in 1 yr. "after the date of last use" if hazardous. WY ADC OIL GEN Ch. 4 s 1(ii), (qq) (2011).

4.12 Disposing of Waste

Handling the large quantities of waste generated by shale gas development may be the greatest environmental challenge facing states with enhanced shale development activity. As discussed above, most wastes associated with oil and gas exploration and production, including produced water, drilling fluids, drill cuttings, and flowback water, are exempt from federal hazardous waste disposal requirements.[333] From the shale gas development perspective, the most important wastes that *remain* federally regulated are unused fracturing fluids and acids.[334] As new types and larger volumes of waste are generated as a result of flowback water from fracturing, states must quickly respond.

Disposal practices for drilling fracturing waste vary substantially by state and by the type of waste. Most states allow operators to dispose of drill cuttings—particularly those uncontaminated by petroleum—on site. Liquid wastes such as produced water and flowback water typically must be disposed of either through land application, a centralized exploration and production (E&P) facility, a wastewater treatment plant, an underground injection control well,[335] or recycling.[336] Underground injection control well disposal has been common in the south and the west, whereas operators in the northeast have tended to dispose of flowback waste through POTWs. All POTWs accepting new wastes, such as flowback water, must obtain a new federal Clean Water Act point source discharge permit (a National Pollutant Discharge Elimination System or "NPDES" permit),[337] although, as discussed below, the EPA has expressed concerns that POTWs may not be equipped to adequately treat flowback water.[338] For operators that

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[333] Envtl. Protection Agency, Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations 10 (Oct. 2002).

[334] *Id*. at 11.

[335] *See* Dancy, *supra* note 39, at 15 (noting that "[m]ost produced water is disposed of in underground injection control wells").

[336] *See* Rahm, *supra* note 131, at 2977 (describing various disposal practices).

[337] Weston, *supra* note 221, at 35 (noting that "[e]ach publicly owned treatment works . . . must obtain NPDES permitting agency approval prior to receipt of new types of industrial wastewater . . . that were not reflected in their original NPDES permit application" and that "[a]ll states require POTWs to provide notice to state permitting authorities and to obtain NPDES permit modification if necessary for acceptance of new types of influent sources").

[338] EPA Seeks More Information from Natural Gas Drilling Operations to Ensure Safety of Wastewater Disposal, May 12, 2011, http://yosemite.epa.gov/opa/admpress.nsf/0/4816775AD0E881AB8525788E006A91ED (requesting

dispose of flowback and other wastes in underground injection control wells, these wells must be permitted under the Safe Drinking Water Act to ensure that they will not leak and endanger underground sources of drinking water.[339]

In addition to implementing federal requirements in cases where states have received permitting authority under federal acts, states have added some of their own restrictions on disposal. In 2010, Pennsylvania implemented a new regulation that required operators to reduce concentrations of total dissolved solids and other pollutants in flowback water before sending it a to a wastewater treatment plant (publicly owned treatments works, or POTWs). Subsequently, the Commonwealth determined that no flowback water should be disposed of through Pennsylvania POTWs.[340] The EPA also intervened, requiring the largest fracturing companies in Pennsylvania to describe how they have been disposing of their flowback waste.[341] Following the state's request that operators no longer send their waste to POTWs, it appears that operators are recycling much of the waste or sending it across state lines—typically to Ohio—for disposal.[342] West Virginia has similarly struggled to identify ideal waste management strategies, indicating in industry guidance:

> While land application may generally be an option on smaller, shallower wells, it may not be practical in dealing with the volume of water expected at these [Marcellus] sites. Presently, underground injection control (UIC) may be the best option. This practice is generally recognized as being environmentally sound and has proven effective for the past 25 years. However, to handle the expected amount of water, many additional UIC wells will need to be permitted, drilled or converted. The Office of Oil and Gas issues Class II UIC permits for brine and fluid disposal. Currently, WV has only two permitted commercial UIC wells

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Pennsylvania's Department of Environmental Protection to "[n]otify EPA when facilities are accepting hydraulic fracturing wastewater so EPA can assess if a pretreatment program or additional permit limits are needed).

[339] 42 U.S.C. § 300h (West 2011).

[340] Dan Hopey & Sean D. Hamill, *PA: Marcellus Wastewater Shouldn't Go to Treatment Plants*, PITTSBURGH POST-GAZETTE, Apr. 19, 2011 (describing the DEP's request that operators voluntarily stop disposing of flowback through POTWs).

[341] EPA, *supra* note 338.

[342] Professor Hannah Wiseman, discussions with Pittsburgh attorneys, Sept. 1-2, 2011.

> available. Operators should seriously consider options for the recycling of fracture treatment flow-back fluid.[343]

Texas, in turn, recently approved one POTW to accept flowback waste and has implemented a number of pilot recycling projects; some of the projects ended as a result of high costs, but others have been successful.[344] The EPA has announced that it will develop federal Clean Water Act standards for the treatment of wastewater from shale gas development by 2014.[345]

Many states require operators proposing to drill and fracture a well to describe how they plan to dispose of their wastes and to report actual disposal practices.[346] Pennsylvania, for example, recently revised its regulations to require that operators develop a "wastewater source reduction strategy"[347] to "maximize the recycling and reuse of flow back or production fluid," and it limits the monthly average of allowable total dissolved solids, chlorides, barium, and strontium in flowback water.[348] The EPA questioned, however, whether water in Pennsylvania was being adequately treated for radioactive and other substances prior to arriving at a POTW and whether the state was adequately monitoring POTW discharges.[349] Still other states have general requirements for disposal in lieu of or in addition to specific provision. Montana provides, for example, "The operator of a drilling well must contain and dispose of all solid waste and

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[343] West Virginia Department of Environmental Protection, Industry Guidance, Jan. 8, 2010, http://www.dep.wv.gov/oil-and-gas/GI/Documents/Marcellus%20Guidance%201-8-10%20Final.pdf.

[344] Railroad Commission of Texas, Water Use in the Barnett Shale, Jan. 24, 2011, http://www.rrc.state.tx.us/barnettshale/wateruse_barnettshale.php.

[345] U.S. Envtl. Protection Agency, EPA Announces Schedule to Develop Natural Gas Wastewater Standards, Oct. 20, 2011, http://yosemite.epa.gov/opa/admpress.nsf/d0cf6618525a9efb85257359003fb69d/91e7fadb4b114c4a8525792f00542001!OpenDocument.

[346] *See, e.g.*, Colorado Oil and Gas Conservation Commission Rule 216c (requiring "[a] plan for the management of exploration and production waste").

[347] *See* 25 PA. CODE. § 95.10(b) (West 2011); *see also* 39 PA. BULL. 6467 (Nov. 7, 2009), *available at* http://www.pabulletin.com/secure/data/vol39/39-45/2065.html (last visited Mar. 27, 2011); Environmental Quality Board, Proposed Rulemaking, Wastewater Treatment Requirements, http://pabulletin.com/secure/data/vol39/39-45/2065.html.

[348] 25 PA. CODE. § 95.10(b) (West 2011).

[349] Letter from Shawn M. Garvin, Regional Administrator, Region III EPA to Michael Krancer, Secretary, Penn. Dep't. of Envtl. Protection, May 12, 2011, *available at* http://www.epa.gov/region03/marcellus_shale/pdf/letter/krancer-letter5-12-11.pdf.

produced fluids that accumulate during drilling operations so as not to degrade surface water, groundwater, or cause harm to soils."[350]

Another important category of disposal involves the disposal of wastes with naturally occurring radioactive materials, typically called "NORM" wastes—drill cuttings, produced water, and flowback.[351] As Joseph Dancy explains, "Radioactivity is not a hazardous 'characteristic' under RCRA, and low level oil field radioactive wastes are generally not regulated as a RCRA hazardous waste" unless these wastes contain materials with other RCRA hazardous characteristics (corrosivity, for example) or are mixed with wastes listed as hazardous under RCRA.[352] Therefore, states shoulder the bulk of the responsibility for regulating oil and gas NORM waste disposal. "In many case more than one state agency" regulates NORM, as illuminated by several of the examples in Dancy's paper.[353] In Texas in 1994, for example, the Railroad Commission regulated the disposal of NORM wastes from oil and gas operations, while the Department of Health (now the Texas Department of State Health Services) had "jurisdiction over the handling, transportation, and NORM contaminating materials"—thus potentially requiring oil and gas operators, under then-new rules, to obtain a general license from this department.[354] This general regulatory regime remains in place today, with the Railroad Commission controlling oil and gas NORM wastes under the Texas Administrative Code and leaving certain regulation—including equipment decontamination—to the Department of State Health Services.[355] The Railroad Commission regulations prohibit the disposal of NORM wastes (other than produced water) "by discharge to surface or subsurface waters" and "by spreading on public or private roads."[356] They allow disposal of NORM wastes "in a plugged and abandoned well" "at least 250 feet below the base of usable water quality," through treatment and burial at

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[350] Mont. Admin. R. 36.22.1005 (2011).
[351] *See* Weston, *supra* note 221, at 34 (noting NORM as a "constituent of concern" in flowback water).
[352] Dancy, *supra* note 39, at 25.
[353] *Id*.
[354] *Id*. at 26.
[355] Railroad Comm'n. of Tex., NORM – Naturally Occurring Radioactive Material, http://www.rrc.state.tx.us/environmental/publications/norm.php.
[356] 16 Tex. Admin. Code § 4.611 (2011).

the site where NORM was generated, landfarming at the site where the NORM waste was generated, "disposal at a licensed facility," or injection into a disposal well.[357] Louisiana similarly allows disposal of NORM in plugged and abandoned wells if the operator first obtains a permit.[358]

An additional consideration in oil gas waste disposal is the centralized E&P waste disposal facility, which accepts a variety of RCRA-exempt exploration and production wastes. Although Table 10 do es not describe state requirements for these facilities, a brief introduction to regulation of these facilities is in order. Colorado, for example, requires sampling of all water wells "within a one (1) mile radius of the proposed facility" prior to the construction of this type of facility; an operating plan that provides for emergency response, site security, inspection and maintenance, and other safety precautions; surface water diversion to accommodate a one-hundred year, twenty-four hour flood event; and other measures.[359] New Mexico similarly requires that centralized disposal facilities have a "be st management practice plan to ensure protection of fresh water, public health, safety, and the environment," a plan to control water runoff, a "leachate management plan," [360] an "inspection and maintenance plan,"[361] and other measures.

No matter the method of disposal chosen for various drilling and fracturing wastes, disposal poses a number of environmental and health risks. If the waste is not adequately treated prior to arriving at a POTW and the POTW cannot handle the new types and quantity of waste, levels of total dissolved solids, radioactive substances, and other pollutants in the receiving stream may rise to unhealthy levels. If drilling and fracturing wastes are applied to land surfaces and then run off into a surface water body, or to soils or surface waters with connections to underground

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[357] 16 Tex. Admin. Code § 4.614 (2011).

[358] Louisiana Dept. of Envtl. Quality, Norm Disposal in a Well to be P&A, http://www.deq.louisiana.gov/portal/Portals/0/permits/Radiation/PDF%20RPD-34%20NORM%20Disposal%20in%20a%20Well%20to%20be%20PA%2006.pdf.

[359] Colorado Admin. Code § 404-1:908 (2011).

[360] NM Admin. Code § 19.15.36.8 C. (2011).

[361] NM Admin. Code § 19.15.36.8 L. (2011).

waters, there is also a risk of contamination. Some states, including Oklahoma[362] and West Virginia,[363] still appear to allow land application of flowback water. Although Oklahoma's regulations allow this, the Oklahoma Corporation Commissioner has stated that land application is not permitted.[364] Oklahoma should revise its regulations to make this clear. West Virginia, in turn, has stated that land applications of large volumes of flowback may not be "practical,"[365] but it, too, should ban the practice or severely constrain land application to areas where resources will not be negatively impacted.

Tables 11a to 11f provide examples of state regulation of disposal of oil and gas exploration and production wastes with respect to the following:

- Drill cuttings from water-based drilling
- Drill cuttings from petroleum-based drilling
- Water-based drilling fluids
- Oil-based drilling fluids
- Flowback
- Produced water

Table 11a. Regulation of drilling and fracturing waste disposal: Drill cuttings from water-based drilling

AR	*Search did not locate statute, regulation, or policy addressing this issue.*
CO	Interim reclamation: cuttings back-filled in pits. COGCC Rule 1003
KY	*Search did not locate statute, regulation, or policy addressing this issue.*

[362] Okl. Admin. Code § 165:10-7-24 (b)(3), (c)(1),(2),(5), and (7) (West 2011).

[363] *See* State of West Virginia, Department of Environmental Protection, Office of Oil and Gas, Well Work Permit Application Addendum, (requiring the operator to indicate the water disposal method and to "estimate . . . [the percentage that] each facility is to receive, and listing as possible facilities "[l]and [a]pplication, "UIC" (underground injection control well), "POTW" (publicly owned wastewater treatment plant), "NPDES" (National Pollutant Discharge Elimination System permit under the Clean Water Act to discharge into waters of the United States), and "[o]ther.").

[364] Jim Myers, *"Fracking" Is Termed Eco-Safe at* Hearing, Tulsa World, Apr. 13, 2011, *available at* http://www.tulsaworld.com/news/article.aspx?subjectid=11&articleid=20110413_16_A9_CUTLIN944671.

[365] West Virginia Department of Environmental Protection, Industry Guidance 4 (Jan. 8, 2010), *available at* http://www.dep.wv.gov/oil-and-gas/GI/Documents/Marcellus%20Guidance%201-8-10%20Final.pdf ("While land application may generally be an option . . . [i]n smaller, shallower wells, it may not be practical in dealing with the volume of water expected at these sites.").

LA	On site, surface discharge (but not within parks, etc. or within 1,300 ft. of active oyster bed), or moved offsite to approved commercial facility or transfer station. LAC 43:XIX.313 (2011); LAC 33:IX.708 (2011)
MD	Landfarming (in areas of disturbance), approved disposal facility, other methods approved by MD DOE. COMAR 26.19.01.10 and .06 (2011)
MI	If NORM material encountered, "store, reuse or recycle" after removing free tubulars or reinsert into wellbore and plug.[366]
MT	In manner so as not to degrade water, harm soils. ARM 36.22.1005 (2011)
NM	*Search did not locate statute, regulation, or policy addressing this issue.*
NY	Burial on site; consultation with Division of Materials Mgt. required if water or brine-based mud contains chemical additives. RSGEIS 7.1.9 (2011)
ND	On site. N.D. Admin. Code 43-02-03-19.2 (2011)
OH	*Search did not locate statute, regulation, or policy addressing this issue.*
OK	Commercial pit. OAC 165:10-9-1; land application OAC 165:10-7-28 and 10-7-29
PA	Pit on site or land application (requirements vary depending on whether from above or below casing seat). 25 Pa. Code 78.61 (2011)
TX	Landfarming of drill cuttings obtained while using low chloride drilling fluids, burial of drill cuttings obtained while using drilling fluids with more than 3,000 mg/liter chloride concentration 16 TAC § 3.8(d)(3) (2011)
WV	*Search did not locate statute, regulation, or policy addressing this issue.*
WY	*Search did not locate statute, regulation, or policy addressing this issue.*

[366] In the Matter of: The Need and Desirability to Issue an Order Establishing Particular Requirements for Plugging of Wells Where Naturally Occurring Radioactive Material (NORM) May be Present, Mich. Dept. Nat. Res. Order NO. 3-6-92. http://www.michigan.gov/deq/0,1607,7-135-3311_4111_4231-9171--,00.html indicates that this case, cited from: http://www.michigan.gov/documents/deq/ogs-oilandgas-sow-3-6-92_261340_7.pdf.

Table 11b. Regulation of drilling and fracturing waste disposal: Drill cuttings from petroleum-based drilling

AR	Class 1 landfill or other ADEQ-approved methods. AOGC Rule B-17(i) (2010)[367]
CO	If count as "oily waste,"commercial solid waste facility, land treatment on site, or land treatment at centralized E&P facility. 2 CCR 404-1 Rule 907 (2011)
KY	*Search did not locate statute, regulation, or policy addressing this issue.*
LA	Community well or class II UIC well LAC 43:XIX.313 (2011). No discharge allowed. LAC 33:IX.708 (2011).
MD	See water-based drill cuttings.
MI	*Search did not locate statute, regulation, or policy addressing this issue.*
MT	If used within floodplain, must dispose off site. ARM 36.22.1005 (2011).
NM	*Search did not locate statute, regulation, or policy addressing this issue.*
NY	Part 360 solid waste disposal facility. RSGEIS 7.1.9
ND	On-site disposal. N.D. Admin. Code 43-02-03-19.2 (2011) (does not differentiate betw. water- and oil-based)
OH	*Search did not locate statute, regulation, or policy addressing this issue.*
OK	Commercial pit or land application. OAC 10-7-26 OAC 165: 10-9-1)
PA	Pit on site or land application (requirements vary depending on whether from above or below casing seat). 25 Pa. Code 78.61 (2011)
TX	Burial of drill cuttings obtained while using drilling fluids with more than 3,000 mg/liter chloride concentration 16 TAC § 3.8(d)(3) (2011)
WV	*Search did not locate statute, regulation, or policy addressing this issue.*
WY	*Search did not locate statute, regulation, or policy addressing this issue.*

[367] Because A.O.G.C. Rule B-17(c)(21) defines reserve pits as containing drill cuttings, this section assumes that fluid disposal requirements for reserve pits also apply to drill cuttings.

Table 11c. Regulation of drilling and fracturing waste disposal: Water-based drilling fluids

AR	Land applied, NPDES or state-permitted facility, Class II UIC well, down well bore, solidified and buried in situ. AOGC Rule B-17
CO	Class II UIC well, commercial solid waste disposal facility, land treatment/land application at centralized E&P waste mgt. facility, "drying and burial in pits on non-crop land", land application. COGCC Rule 907
KY	*Search did not locate statute, regulation, or policy addressing this issue.*
LA	See water-based drill cuttings.
MD	*Search did not locate statute, regulation, or policy addressing this issue.*
MI	Approved UIC well. MICH. ADMIN. CODE R 324.703 (2011)
MT	In manner so as not to degrade water, harm soils. ARM 36.22.1005 (2011).
NM	All liquids from temp. pits must be sent to "division-approved facility" or recycled/reused. NM ADC 19.15.17.13 B. (2011). Those from permanent pits must go to division-approved facility. *Id*. at C.
NY	*Not indicated in 7.1.3.2 of RSGEIS ("drilling fluids")*
ND	Top water from reserve pit removed and "disposed of in an authorized disposal well or used in a manner approved by the director" 43-02-03-19.2
OH	*Search did not locate statute, regulation, or policy addressing this issue.*
OK	Commercial pit. OAC 165:10-9-1; commercial soil farming OAC 165:10-9-2; land application OAC 165:10-7-19 (for water-based fluids from earthen tanks)
PA	*Search did not locate statute, regulation, or policy addressing this issue.*
TX	Landfarming for low-chloride fluids, burial for dewatered fluids with "chloride concentration in excess of 3,000 mg/liter." 16 TAC § 3.8 (d)(3)
WV	*Search did not locate statute, regulation, or policy addressing this issue.*
WY	Landfarming, landspreading, roadspreading w/ DEQ and Oil and Gas Conservation Commission permission. WY ADC OIL GEN Ch. 4 s 1 (mm) (2011).

Table 11d. Regulation of drilling and fracturing waste disposal: Oil-based drilling fluids

AR	Class 1 landfill or re-use at another well location. AOGC Rule B-17
CO	Disposal at commercial solid waste disposal facility, land treatment onsite, land treatment at centralized E&P waste mgt. facility. COGCC Rule 907
KY	*Search did not locate statute, regulation, or policy addressing this issue.*
LA	Community well or class II UIC well LAC 43:XIX.313 (2011). No discharge allowed. LAC 33:IX.708 (2011)
MD	*Search did not locate statute, regulation, or policy addressing this issue.*
MI	Approved UIC well. MICH. ADMIN. CODE R 324.703 (2011)
MT	If used within floodplain, must dispose off site. ARM 36.22.1005 (2011).
NM	All liquids from temp. pits must be sent to "division-approved facility" or recycled/reused. NM ADC 19.15.17.13 B. (2011).[368]
NY	Pit liners for pits that contain oil-based drilling fluids must be disposed of in solid waste landfill. R SGEIS 5.13.12
ND	*Search did not locate statute, regulation, or policy addressing this issue.*
OH	*Search did not locate statute, regulation, or policy addressing this issue.*
OK	Soil farming of oil-based drilling muds prohibited. OAC 165:10-9(i) (West 2011)
PA	Potential discharge from pit (when mixed with water) with DEP approval 25 Pa. Code § 78.60; after dewatering, residual waste may be disposed of in pit on site following certain requirements (setbacks, etc.) 25 Pa. Code § 78.62
TX	*Search did not locate statute, regulation, or policy addressing this issue.*
WV	*Search did not locate statute, regulation, or policy addressing this issue.*
WY	Landfarming, landspreading, roadspreading w/ DEQ and Oil and Gas Conservation Commission permission; permitted disposal facility, bioremediation, burial after encapsulation if below certain dissolved solid and oil concentrations. WY ADC OIL GEN Ch. 4 s 1 (ii), (mm) (2011)

[368] Those liquids from permanent pits must go to division-approved facility. NM ADC 19.15.17.13 C. (2011).

Table 11e. Regulation of drilling and fracturing waste disposal: flowback

AR	No disposal in mud, circulation, or reserve pit or through land application, except temp. storage allowed as part of flow-back recycling system. AOGC Rule B-17 (2011)
CO	If "workover" fluids encompasses flowback, disposal at solid waste disposal facility, treatment at centralized E&P waste management facility, Class II UIC well. COGCC Rule 906
KY	*Search did not locate statute, regulation, or policy addressing this issue.*
LA	"Workover, completion, and stimulation" fluids: community well, class II UIC well, or surface discharge, where authorized. LAC 43:XIX.313 (2011)
MD	"Treatment facility, pit, impoundment, or dam"[369]
MI	UIC. MICH. ADMIN. CODE R 324.703 (2011)
MT	Nothing flowback-specific. In manner so as not to degrade water, harm soils. ARM 36.22.1005 (2011).
NM	*Search did not locate statute, regulation, or policy addressing this issue.*
NY	Approved wastewater treatment plant or recycling/reuse. R SGEIS 7.1.8
ND	"All waste associated with exploration or production of oil and gas must be properly disposed of in an authorized facility in accord with all applicable local, state, and federal laws and regulations." N.D. Admin. Code 43-02-03-19.2 (2011)
OH	*Search did not locate statute, regulation, or policy addressing this issue.*
OK	Recycling, burial, noncommercial pits, underground injection.[370] OAC 165:10-7-24 (b)(3), (c)(1),(2),(5), and (7)
PA	Previously, wastewater treatment plants after TDS treatment. Currently,per "request" of DEP, waste must be disposed of through UIC well, recycling, or out-of-state disposal 25 PA ADC 95.10 (2011)[371]
TX	Underground injection control well. 16 TAC § 3.9(1) (2011). Unclear whether contents of completion/workover pits include flowback, but dewatered contents from these pits may be disposed of within the pit on site. 16 TAC § 3.8(d)
WV	Land application, UIC wells. WV DEP Industry Guidance
WY	*Search did not locate statute, regulation, or policy addressing this issue.*

[369] Maryland Department of the Environment, Application for Gas Exploration and Production, Section 4. Marcellus Shale Wells/ Hydro Fracturing Addendum, Form No. MDE/LMA/PER.045 at 7, Oct 2008, available at http://www.mde.state.md.us/assets/document/permit/MDE-LMA-PER045.pdf.

[370] Oklahoma Corporation Commissioner Jeff Cloud reports that the Commission requires either recycling or underground injection. *See* Jim Myers, *"Fracking" Is Termed Eco-Safe at Hearing*, Tulsa World, Apr. 13, 2011, *available at* http://www.tulsaworld.com/news/article.aspx?subjectid=11&articleid=20110413_16_A9_CUTLIN944671.

[371] For a description of the DEP request, *see* Hopey, *supra* note 7.

Table 11f. Regulation of drilling and fracturing waste disposal: produced water

AR	Identical to water-based drilling fluids rule. AOGC Rule B-17
CO	Class II UIC well, evaporation/percolation in pit, permitted commercial facility, roadspreading outside of sensitive areas, discharge into state waters with permit, lined pit at a centralized E&P waste management facility, reuse and recycling . 2 CCR 404-1 Rule 907 (2011)
KY	Enhanced recovery well, UIC well, permitted surface discharge (including discharge into water), evaporation, reverse osmosis, other approved method—provided that no method violates water quality standards. 401 KAR 5:090 (2011)
LA	"Subsurface injection into legally permitted or authorized operators saltwater disposal wells, commercial saltwater disposal wells, enhanced recovery injection wells, community saltwater disposal wells, or gas plant disposal wells." LAC 43:XIX.303.B (2011)
MD	*Search did not locate statute, regulation, or policy addressing this issue.*
MI	Approved UIC well, ice or dust control in limited circumstances. MICH. ADMIN. CODE R 324.703 (2011); MICH. ADMIN. CODE R 324.705 (2011)
MT	If >15,000 ppm TDS, Class II UIC well or lined or unlined earthen pit if can show volume of water to be disposed of in each pit will not exceed 5 bbl/day monthly and won't degrade water or harm soils. ARM 36.22.1226 (2011)
NM	"Delivery to a permitted salt water disposal well or facility, secondary recovery or pressure maintenance injection facility, surface waste management facility or permanent pit [permitted]; or to a drill site for use in drilling fluid." NM ADC 19.15.34.12 (2011)
NY	Possible road spreading after beneficial use determination and NORM analysis; POTWs with approved pre-treatment program. R SGEIS 5.16.6; 7.1.7.2
ND	See flowback
OH	UIC (except exempt Mississippian wells). Ohio Rev. Code § 1509.22(C) (West 2011); road application if approved by municipality and meets other conditions. Ohio Rev. Code § 1509.226 (West 2011)
OK	Produced water from tanks may be discharged on to land with maximum Exchangeable Sodium Percentage, slope, min. depth to bedrock, min. depth of water table, etc. OAC 165:10-7-17
PA	POTW after treatment for TDS, etc. (*But see* flowback disposal discussion. Recent move away from POTWs). 25 PA ADC §95.10
TX	Underground injection control well. 16 TAC § 3.9(1) (2011)
WV	*Search did not locate statute, regulation, or policy addressing this issue.*
WY	Landfarming, landspreading, roadspreading w/ DEQ and Oil and Gas Conservation Commission permission. WY ADC OIL GEN Ch. 4 s 1 (mm) (2011). If pit solids have high concentration of salt, permitted facility, encapsulation, or chemical or mechanical treatment. WY ADC OIL GEN Ch. 4 s 1 (ii), (mm) (2011)

4.13 Restoring the site

After drilling and fracturing are completed and an operator has disposed of the waste, many states require that the operator restore the site. Operators often must empty pits of waste and fill them in, test soils for contamination remove any contaminated soils, stabilize the soils on site, and, in some cases establish vegetative cover on the site.[372] Arkansas requires that pits and the "applicable portion of the drill pad not utilized for production purposes . . . s hall be returned to grade, reclaimed and seeded within a reasonable amount of time not to exceed one hundred eighty days (180) days after the drilling or workover rig is removed from the site."[373] Kentucky provides, in turn, "In conjunction with the plugging and abandonment of any well or the reworking of any well, the operator shall restore the surface and any improvements thereon to a condition as near as practicable to their condition prior to commencement of the work."[374] Although most states have comprehensive remediation requirements, states should consider the additional surface contamination that may have occurred as a result of fracturing, require testing for hazardous chemicals, and update their remediation requirements accordingly, as Colorado has done.[375]

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[372] Okla. Admin. Code § 165:10-7-16(c)(7) (2010).

[373] Rule B-17.

[374] Kentucky Rev. Stat. § 353.595 (2011).

[375] COGCC Rule 909 (requiring pit remediation); COGC Table 910-1 (requiring reduction of contamination to allowable concentrations); STRONGER, Colorado Hydraulic Fracturing State Review 25, Oct. 2011, *available at* http://www.strongerinc.org/documents/Colorado%20HF%20Review%202011.pdf (describing site remediation).

5 Conclusion

The majority of state regulations that apply to shale gas development were written before shale gas development became common, although some states have revised regulations to specifically address shale gas development and hydraulic fracturing. Arkansas, for example, requires (for fractured wells) that surface casing "have sufficient internal yield pressure to withstand the anticipated maximum pressure to which the casing will be subjected in the well" and applies specific cementing requirements to fractured wells. Pennsylvania also has updated its casing and cementing requirements and its requirements for the treatment of flowback water prior to disposal. Montana, North Dakota, and Wyoming have similarly updated their casing requirements to require pressure tests or the use of a pressure relief valve "on the treating lines between pumps and wellhead," among other protections. New York, in turn, has engaged in a comprehensive environmental review of the impacts of high-volume hydraulic fracturing in shales and has proposed aggressive environmental controls, such as requirements for setbacks of wellpads from natural resources, air emission controls on drilling and fracturing equipment, and the use of steel tanks to hold drilling and fracturing waste. Colorado recently reviewed its entire oil and gas code and comprehensively updated it, implementing buffer zones around public water supplies, improving remediation requirements, and adding wildlife protections, among other measures. Oklahoma has provided a helpful summary of all of its existing regulations that apply to fracturing operations but has not updated many of its regulations; it is including hydraulic fracturing, however, in a five-year "strategic plan."[376] Texas, in contrast, has not revised any of its oil and regulations to address fracturing, with the exception of chemical disclosure.

Most of the recent regulatory revisions tend to focus on three prominent concerns: that shale gas wells are cased properly so as to avoid contamination of underground water supplies with methane; that the content of the fracturing solutions used be known; and that the large quantities of wastewater produced are disposed of properly. Many of these revisions have reflected suggested regulatory improvements in the literature. The Secretary of Energy Advisory Board

[376] State Review of Oil and Natural Gas Environmental Regulations, Oklahoma Hydraulic Fracturing State Review, January 2011, *available at* http://www.occeweb.com/STRONGER%20REVIEW-OK-201-19-2011.pdf.

Shale Gas Production Subcommittee, for example, suggested in its ninety-day report that we must "improve public information about shale gas operations,"[377] and chemical disclosure requirements recently enacted in Montana, Texas, and Wyoming take an important step toward this recommendation. Other revisions have reflected guidelines and recommendations of the State Review of Oil & Natural Gas Environmental Regulations, which encourage disclosure of chemicals if a health incident occurs, minimum requirements for casing depths below groundwater, and spill prevention and contingency plans, among other protections.

Despite the regulatory updates in several states and existing, protective regulations in others, significant gaps remain. The paper accompanying this piece, for example, ("State Enforcement of Shale Gas Regulations"), highlights the risks of surface spills, and particularly spills of undiluted fracturing chemicals. New York has proposed best management practices for the transportation of chemicals and secondary containment under chemical transfer operations on wellpads; Colorado has special container laws for hazardous chemicals, and Arkansas, regulates flowback transport. These states have made important steps toward reducing the potential impacts of spills, but the many other states with enhanced oil and gas and fracturing activity must follow this lead. States should review whether Department of Transportation regulations for hazardous materials adequately prevent spills of fracturing fluid.

Other gaps remain in the areas of well casing and cementing, water withdrawal, waste storage, and waste disposal. Professor Duncan notes the importance of long-term well integrity and of avoiding the rare risk of underground well blow-outs during drilling and fracturing. A well that is improperly cased and plugged can leak methane or other substances after it is plugged and also increases the risk of an underground blowout. States that have not yet revised their casing, cementing, and blowout prevention regulations to account for the additional pressure that hydraulic fracturing places on the well should do so. They also should require, as Pennsylvania and several other states have, that if an operator installs used casing, the casing must first be pressure tested. Because fracturing also expands the amount of water required for oil and gas development, states should update water withdrawal monitoring requirements and reconsider the

[377] The SEAB Shale Gas Production Subcommittee Ninety-Day Report, Aug. 11, 2011.

need to permit withdrawals of water for oil and gas development. For the storage and disposal of flowback water after fracturing, states that have not yet done so should update their waste storage laws to describe the types of pits in which flowback water should be stored. They also should implement liner requirements for flowback storage and ensure that flowback pits are not located near surface waters or other important natural resources. Finally, states must update their waste disposal laws to account for the addition of a new waste stream—flowback water—from the oil and gas development process. As the EPA works toward writing wastewater standards, states should ensure that flowback is not land applied and is adequately treated if sent to a plant for wastewater treatment and discharge to surface waters.

The maze of regulation that applies to shale gas development—much of which is state regulation—is difficult to navigate, and no one paper can comprehensively describe the regulatory re-evaluation and modification that should occur to address the rise of shale gas development. A number of existing sources, including guidelines from the Ground Water Protection Council and the Council's State Review of Oil and Natural Gas Environmental Regulations, provide a good starting point.[378] These guidelines do not fully address, however, all potential impacts of shale gas development, from seismic testing through site restoration. This paper has briefly explored all core stages of shale gas development and provided examples of regulation at each of these stages in an attempt to inspire further conversation about improved regulation. Much more work is needed, but the authors hope that the regulatory examples here will provide valuable source material for future projects.

[378] Ground Water Protection council, *supra* note xx, at 7 (providing "Key Messages and Suggested Actions").

6 State Enforcement of Shale Gas Regulations

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1 Introduction

The United States is in the midst of a boom in natural gas and oil production, much of which has occurred in shale formations around the country. As shale development has expanded—largely as a result of new horizontal drilling and "slickwater" hydraulic fracturing techniques—questions have arisen regarding the environmental risks of drilling and fracturing in shales and how laws, policies, and regulations (described generally as "regulations" throughout this paper) address these risks. To understand how regulation addresses risks, one must know both the content of regulations and how they are applied through inspections of well sites, notation of violations, and/or enforcement. Regulations have little effect if they are rarely applied to regulated actors; looking to both the content of regulations, violations of the regulations, and enforcement therefore provides a more complete picture of the regulation of shale gas development.

A second paper by this author, entitled "Regulation of Shale Gas Development," addresses the content of federal, regional, state, and local regulations that apply to shale gas development. This paper, "State Enforcement of Shale Gas Regulations," takes up the task of describing how these regulations are applied. It briefly surveys complaints about shale gas and tight sands development lodged by citizens with state agencies,[1] states' notation of environmental violations at shale gas and tight sands[2] wells (abbreviated generally as "shale gas wells" in this paper) both in response to these complaints and as a result of independently-instigated site visits or self-reported violations, and states' capacity to inspect sites and enforce violations noted. The objective of this "on-the-ground" review of shale gas development regulatory activities is to offer a preliminary identification and analysis of environmental effects of shale gas development and how states address through citations of violations and/or initiation of enforcement action. This paper also aims to illuminate media accounts and academic perspectives on shale gas

[1] In places, the paper also addresses tight sands and shale oil development, as these types of development use similar technologies and can provide important lessons for shale gas development.

[2] Throughout this paper, the author generally refers only the shale gas wells because these wells comprised the largest component of the enforcement data collected.

development, described in separate papers by Professors Matt Eastin and Suzanne Pierce, by comparing the academic and media focus with the effects that states have identified through complaints and inspections. Looking to state enforcements of environmental regulations at shale gas and tight sands sites (where wells also are typically hydraulically fractured) provides a glimpse into the types of risks posed by drilled and fractured wells and the potential magnitude of these risks.[3]

[3] Addition information that might help to describe risks would be an analysis of the types of industry actors involved in horizontal drilling and fracturing. Large companies with adequate capital and years of experience, for example, may tend to cause fewer violations than would, for example, small ones. Indeed, for several of the more serious violations noted at well drilling and fractures sites in Texas, the operator involved entered bankruptcy proceedings. *See* Lease no. 0613349, docket 09-0260793, Oak Hills Drilling & Oper., LLC (enforcement records indicate master default order signed with requirement that "respondent must plug wells and otherwise place in compliance, notation that operator is in bankruptcy); Lease no. 0628399, docket 09-0250732, Saddle Creek Energy Development (enforcement records indicate a $23,400 penalty assessed for improper disposal methods and that operator is in bankruptcy). This study does not describe the specific entity that caused the violations described at sites. The data underlying the study, however, include company names. Future investigation that included an analysis of violations and the size of the entity causing the violation could offer a valuable predictive tool with respect to risk.

2 Scope of Coverage; Objectives and Methods

This paper addresses both regulatory and scientific components of the "Fact-Based Regulation for Environmental Protection in Shale Gas Resource Development" project. The paper investigates violations of environmental and oil and gas regulations noted by state agency staff and, where applicable, enforcement of these violations, combined with states' capacity to enforce.[4] This tends to show the types of environmental effects caused by shale gas development. If states with adequate inspection and enforcement capacity (and thus the capacity to investigate and respond to a range of potential environmental effects) note a large number of violations for chemical spills at the surface, for example, this may suggest that surface spills are one of the primary environmental effects of shale gas development.[5] Understanding states' identification of violations and accompanying enforcement actions also may provide a more nuanced picture of states' regulatory responses to the effects of shale gas development by showing the types of effects that states have prioritized for response.

The report assumes that state enforcement of laws regulating shale gas development shows some of the most common environmental effects of this development, with several caveats. When states have little capacity to enforce regulatory requirements or inspect sites for violations, enforcement data are insufficient to accurately describe the effects of shale gas development.[6] Further, even if states have adequate inspection capacity and therefore respond to a range of potential environmental effects, field inspectors may tend to notice certain violations but not others: Spills, inadequate fencing around a well pad, and a failure to revegetate a site, for

[4] This paper addresses capacity to enforce by identifying the number of field inspectors and attorneys at agencies. It does not investigate, however, states' political will or commitment to enforce, which also may affect the number of inspections and enforcements.

[5] Other factors also may contribute to a high number of spill responses, of course. A field inspector can more easily detect surface spills than underground water contamination, for example. Enforcement actions at a minimum do, however, point to *some* of the effects.

[6] Low levels of enforcement activity could be caused by several factors. First, low enforcement levels might suggest that shale gas development has few environmental effects and therefore causes few violations of environmental regulations. Alternatively, the levels might indicate that shale development has environmental effects that would cause violations of the state's laws but that the state has low enforcement capacity.

example, may be obvious; detection of alleged effects such as water well contamination and air emissions often requires special equipment and may be not be detected if not tested. On the other hand, a large number of violations such as spills and inadequate fencing may simply suggest that these are the most common issues encountered.

To identify states' enforcement of environmental regulation of shale gas development and their capacity to enforce, the author, with the valuable assistance of six University of Texas School of Law research assistants, attempted to collect data, categorize, and analyze data on complaints and enforcements from fifteen of the sixteen states discussed in "State Regulation of Shale Gas Development."[7] Specifically, for the period of approximately 2008-2011,[8] we attempted to obtain the following data from state oil and gas (and, in limited cases, environmental) agencies:

- the number of annual field inspectors devoted to oil and gas enforcement and, specifically, to enforcement at shale gas or oil and/or tight sands wells, if any;
- the total number of annual field inspectors at the agency (if none were assigned specifically to oil and gas or shale gas or oil and/or tight sands development);
- the total number of field inspector visits to shale gas or oil and/or tight sands sites (or to oil and gas well sites, if shale gas/oil and tight sands information was not available);
- the total number of attorneys annually assigned to enforce violations at oil and gas wells;
- all violations of municipal, state, and/or federal laws identified at shale gas and tight sands well sites and at the disposal stage;
- enforcement of municipal, state, and/or federal laws at shale gas well sites and at the disposal stage; and

[7] Due to time constraints and the fact that few shale gas wells have been drilled in Kentucky, the author omitted this state from her enforcement analysis.

[8] The time period for data collected varied among states due to the period over which shale development has occurred and the quantity of information that each state was willing or able to collect and provide).

- environmental testing, sampling, and/or monitoring at shale gas well sites, including any agency determinations of whether shale gas development caused environmental or health effects.

To locate data on violations and enforcement of environmental laws at well sites, we first searched for complaint, violation, and enforcement data in online databases and other web-based information made publicly available by state oil and gas and environmental agencies. In cases in which sufficient data were not available online, we then contacted agencies by phone and/or e-mail, requesting all complaints, violations, and enforcements at shale gas, shale oil, and tight sands wells recorded between 2008 and 2011 (or earlier if substantial development began prior to 2008). We followed up with official public records requests if we still had not obtained the needed data. For data on employees and inspections made, we also scanned agency websites, requested the information from agencies, and, for some states, reviewed reports from the State Review of Oil and Natural Gas Environmental Regulations, which survey state oil and gas agencies and voluntarily review these agencies' regulatory programs to identify strengths and areas for improvements in the programs. We also surveyed some state agencies' sunset reports, which describe agencies' staffing and performance.

We emphasize caution in drawing overly broad conclusions from the data described in Part 4. First, the violation and enforcement data collected are, by necessity, incomplete. The manner in which we requested and obtained data from each state differed, partially due to state norms and initial agency responses to our requests. Responses to these requests differed; some states provided full data sets of all violations and enforcements at shale and/or tight sands sites over a recent time period (ranging from three to ten years), others provided partial data sets, and still others provided no information. States also have a variety of methods for collecting, recording, and organizing enforcement data, which influenced the data that they were able to provide. New York, for example, does not keep separate enforcement records,[9] requiring a review of every

[9] Telephone Conservation between Joel Daniel, Research Assistant to Professor Wiseman, and Jennifer Maglienti, New York Department of Environmental Conservation, August 3, 2011.

well file to identify whether the agency has enforced environmental regulations for each well. (New York also has not yet allowed high-volume hydraulic fracturing within the state unless operators first conduct a site-specific review, which makes New York data less relevant from the perspective of fracturing.)

For states that maintain records of inspections, violations, and post-inspection enforcement that are separate from general well files, some keep online records, while others do not. Some states are in the process of moving from hard copy to online record systems and indicated that any data provided would be incomplete.[10] States' differing methods of maintaining and reporting inspection, violation, and enforcement also may lead, in some cases, to inaccurate reporting. This report only conveys the information provided by states and does not certify the accuracy of that information. Finally, even when we obtained comprehensive enforcement data from a state, the state may have failed to preserve or investigate certain complaints about shale gas development, and we were unable to determine from the information collected which complaints were not preserved and/or not addressed. Without more information about these complaints, we cannot properly analyze their validity.

The data described in Section 4 also are incomplete due to the dual nature of some states' oil and gas environmental regulation. Although we attempted to contact both environmental and oil and gas agencies to obtain data on enforcement at shale gas sites, we focused primarily on the agency in the state with the primary authority over oil and gas wells. Most of the enforcement data that we received therefore came from oil and gas agencies or the oil and gas division of states' environmental agencies. It is important to note, therefore, that particularly in the states where other sections of environmental agencies have key jurisdictional authority over oil and gas development, the enforcement data are incomplete. This is particularly relevant for issues such as air quality and wastes with naturally occurring radioactive materials ("NORM"): In many

[10] *See, e.g.*, Telephone Conservation between Hannah Wiseman, Assistant Professor, and Tom Richmond, Montana Department of Natural Resources, Board of Oil and Gas, August 16, 2011 (indicating that Montana is moving to an online system and expressing concern that any enforcement data provided would be incomplete, as the records are in transition).

states, both environmental and oil and gas agencies have jurisdiction over certain aspects of NORM handling and disposal, as discussed in "State Regulation of Shale Gas Development." Finally, of the states that provided violation and enforcement data, several of the data sets were not complete.[11]

Finally, a small percentage of the violations described in Part 4 may be associated with wells that were not fractured. Some states do not maintain information in their files on whether a well was fractured or not or cannot sort by this function. For these states, we attempted to identify complaints, violations, and enforcements at all wells drilled in counties where there are shale or tight sands formations; this was the best proxy available for identifying fractured wells, but it is not perfect; some wells drilled in counties overlying shale or tight sands formations may not in fact have been fractured. In light of the fact that this study addressed all stages of shale development, however—including the site development and drilling that occurs for all types of oil and gas wells—even enforcements that occurred at non-fractured wells can contribute to our understanding of the types of environmental effects that may arise at all stages of the shale gas development process.

Taken together, the incomplete complaint and enforcement data examined below offer a preliminary picture of the types of environmental effects of shale gas development and state responses to these effects. Identifying complaints relating to and environmental enforcement of shale gas development is not a perfect measure of potential environmental effects; effects may go unnoticed by gas companies, the media, individuals and organizations lodging complaints, and/or regulatory agencies. The data described below may, however, suggest the range of potential environmental effects from well development and from the fracturing process itself and how regulatory bodies are responding to these effects.

[11] The author has additional violation and enforcement data from Colorado, Ohio, Pennsylvania, and West Virginia that are not discussed in detail in this paper due to time constraints. The author is continuing to categorize and analyze these data; please contact her if you wish to see updated results.

3 Enforcement Capacity

To measure a state's capacity to inspect sites, to identify violations of environmental law, and to conduct post-violation enforcement—and thus the likelihood that the state's described below identified a reasonably broad range of potential environmental effects in their shale gas inspection and enforcement activities—we collected data on staff and inspection numbers, as described in Section 3. Several states have not yet responded to our inquiries about enforcement capacity, but Table 1 summarizes the data that we have obtained to date and includes data from additional sources, including the State Review of Oil and Natural Gas Environmental Regulations and a sunset report prepared by the Railroad Commission of Texas.

Table 1. State Shale Gas Development Inspection and Enforcement Capacity, 2008-2011

	CO[12]	LA[13]	MD[14]	MI[15]	MT	NM[16]	ND[17]	OH	OK	PA[18]	TX	WY[19]
Number of active shale gas, tight sands, and/or oil shale wells 2008			0	308						195	10,146[20]	
2009			0	153						768		25 wells completed in 2009-11 period[21]
2010			0	120						1,386		
2011			0	72						1,015		

[12] Data for the Colorado Oil and Gas Conservation Commission.

[13] Data for the Louisiana Department of Natural Resources, Office of Conservation.

[14] Data for Maryland Department of the Environment.

[15] Data for the Michigan Department of Environmental Quality. Number of wells drilled for Michigan describes shale gas wells.

[16] Data for the New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division.

[17] Data for the North Dakota Industrial Commission, Department of Mineral Resources, Oil and Gas Division.

[18] Data for the Pennsylvania Department of Environmental Quality, Bureau of Oil and Gas Management.

[19] Data for the Wyoming Oil and Gas Conservation Commission (OGCC) unless otherwise indicated. DEQ refers to the Wyoming Department of Environmental Quality, Water Quality Division.

[20] Railroad Comm'n of Tex., Newark (East) Barnett Shale Well Count, http://www.rrc.state.tx.us/barnettshale/barnettshalewellcount1993-2010.pdf.

[21] E-mail from Thomas E. Doll, State Oil and Gas Supervisor, Wyoming Oil and Gas Conservation Commission, to Jeremy Schepers, June 21, 2011 (To-date only 25 wells have been completed in these unconventional oil reservoirs, 10 in the Niobrara shale, 6 Sussex, 6 Turner, 2 Parkman and 1 Frontier sand well."). Note, however, that beyond the unconventional reservoirs, many more gas wells have been hydraulically fractured in Wyoming. *See id*. ("Statewide

Table 1. State Shale Gas Development Inspection and Enforcement Capacity, 2008-2011(continued)

	CO	LA	MD	MI	MT	NM	ND	OH	OK	PA	TX	WY
Total number of field inspectors in agency 2008	NA	6422	NA	27	6	16	NA	17-2223			12524	NA
2009	NA	62	NA	25	7	16	NA	17-22		3525		NA
2010	NA	61	4	24	7	16	NA	17-22	4826	76		NA
2011	12	59	4	22	7	16	11	28				12 O&G 7 DEQ27
Of total inspectors listed above, total number of inspectors assigned to shale gas wells 2008		4328	NA	27		16	NA	NA				NA
2009		4129	NA	25		16	NA	NA				NA
2010		4030	431				NA	NA				
2011		3832	433				NA	NA				

in 2008 1,148 wells were hydraulically fractured and 6,376 individual treatments were performed, in 2009 746 wells had 5,675 individual HF treatments, and in 2010 704 wells had 5,974 individual HF treatments.”).

[22] Number indicates “number of staff positions authorized at the beginning of the fiscal year for field inspectors.”

[23] Number indicates full time employees, which “ranged from 17-22 from 2008-2010.” Response of Tom Tugend, Deputy Chief, to inquiry from Matt Peña, Sept. 26, 2011.

[24] Railroad Comm’n of Tex., Self-Evaluation Report at 97 (Sept. 2009), *available at* http://www.sunset.state.tx.us/82ndreports/rct/ser.pdf.

[25] Sabrina Shankman, New Gas Drilling Rules, More Staff for Pennsylvania’s Environmental Agency, ProPublica, Feb. 9, 2010, *available at* http://www.propublica.org/article/new-gas-drilling-rules-more-staff-for-pennsylvanias-environmental-agency.

[26] *See* State Rev. of Oil & Nat. Gas Envtl. Regs., Oklahoma Hydraulic Fracturing State Review (Jan. 2011), *available at* http://www.occeweb.com/STRONGER%20REVIEW-OK-201-19-2011.pdf.

[27] The Wyoming Department of Environmental Quality’s Water Quality Division has seven field inspectors who spend, on average, half of their time on oil and gas activities. E-mail from John Wagner, Wyoming Department of Environmental Quality, Water Quality Division, to Jeremy Schepers, June 28, 2011.

[28] Attorneys are devoted to oil and gas sites (excluding field inspectors for “pipelines, underground injection control structures, and commercial facilities authorized to dispose of exploration and production waste”), not to hydraulically fractured wells specifically.

[29] *See id*.

[30] *See id*.

[31] Represents inspectors devoted to oil and gas enforcement.

[32] *See supra* note 28.

[33] Represents inspectors devoted to oil and gas enforcement.

Table 1. State Shale Gas Development Inspection and Enforcement Capacity, 2008-2011(continued)

	CO	LA	MD	MI	MT	NM	ND	OH	OK	PA	TX	WY
Number of field inspections 2008		13		11,013[34] (Not specific to shale wells.)		16				144	120,866 (all oil and gas facilities[35])	3
2009		186		13,459		16				323		2
2010		374	22	16,850		16				643		2
2011		363	0	4,396		16				298		2
Number of attorneys devoted to enforcing activities at oil and gas wells 2008		2		3[36]								NA
2009		2		2								NA
2010		2		1								NA
2011		2	1	1								1 1.5 DEQ[37]

As Table 1 demonstrates, the ratio of field staff and inspections to the number of active shale gas, shale oil, or tight sands wells in a state varies widely. Part of this variation is due to differences in reporting. Pennsylvania tallies the number of annual field visits to shale wells, for example, while other state data on site visits represent all oil and gas inspections conducted. Although state enforcement capacities vary, it appears that the states with current shale gas, shale oil, and/or tight sands development for which we obtained data--as well as additional states for which we have not yet compiled enforcement data but obtained capacity numbers--have the enforcement capacity necessary to address, at minimum, a small range of complaints associated

[34] From Joe Petit, Enforcement Section, Resource Management Division, Michigan Department of Environmental Quality, Office of Geological Survey: "The total number of inspections performed in the Cadillac and Gaylord District Offices. This is the area of the state where shale formations are developed. The number is representative of all field inspections performed and not specific to the drilling and completion of shale wells."

[35] Railroad Comm'n of Tex., *supra* note 24, at 19.

[36] Described in response from agency as "enforcement staff."

[37] 1.5 attorneys address water quality issues, and they spend approximately half of their time enforcing oil and gas issues. Wagner, *supra* note 27

with this development and to conduct independent enforcement actions. Some states have much higher enforcement capacity, and larger numbers of inspections, than others; this likely affects the total number of violations noted and enforcement actions taken and may create a more representative set of violations. Michigan conducted nearly 17,000 inspections of all oil and gas wells in the state (not just shale wells) in 2010, for example, and Pennsylvania inspected nearly 1,400 shale wells in the same year.

4 Environmental Effects Associated with State Environmental Violations and Enforcement at Shale Oil, Shale Gas, and Tight Sands Sites

Based on the data presented in Table 1 in Section 3, if one assumes that all states have sufficient enforcement capacity to address at least a representative sample of potential violations as shale gas sites, the types of activities underlying these identified violations and/or enforcement actions may help to demonstrate the types of activities in shale gas and similar unconventional development that cause the most violations. In locating the activities that tend to cause violations of environmental regulations, one also can analyze typical environmental effects. Improperly casing or cementing a drilled well, for example—an improper plugging—can contribute to the groundwater pollution problems that have been emphasized in the media, as discussed in Professor Matt Eastin's paper. Surface spills, in turn, if not recovered and/or remediated, can pollute soil and water. Table 2 summarizes the activities at oil and/or gas wells for which states noted violations. Where noted, the violations are specific to shale gas wells.

Table 2. Oil and Gas violations: Percent of Total by Violation Type (continued on page 18) [38]

	Louisiana: Haynesville Shale wells 2009-2011 158 total violations Percent of total violations[39]	Michigan: Antrim Shale wells 1999-2011 497 total violations Percent of total violations	New Mexico: tight sands and shales (not comprehensive) 2000-2011 77 total violations Percent of total violations	Texas: fractured shale wells, FY 2008-2011 72 total violations[40] Percent of total violations
Construction of access road and well pad				
Erosion and sedimentation		0.8		
Maintenance of site: vegetation, signs, fencing				
Fencing			1.3	
Signs and labeling	20.0	32.5	18.2	5.6
Site maintenance (clearing weeds, for example)		22.4		
Drilling (and potentially fracturing)				
Air quality		0.2		See TCEQ discussion
Casing and cementing	3.0			8.3
Commingling oil and gas	1.5			
Failure to prevent oil and gas waste		0.6		
Fire			1.3	
Gas or oil leak at wellhead/venting		3.0	5.2	1.4
Noise		0.2	1.3	
Odors			0	See TCEQ discussion
Surface spill condensate			1.3	
Surface spill contaminant not indicated		24.5	5.2	
Surface spill diesel			1.3	
Surface spill drilling mud	1.5			
Surface spill oil	0.7	0.4	9.1	
Surface spill produced water	1.5	0.2	33.8	
Wellhead and blowout	3.0	1.0		1.4[41]

[38] It is important to note that Antrim Shale development in Michigan is substantially different from, for example, Barnett Shale development in Texas. For full data on violations and enforcement at Marcellus Shale wells in Pennsylvania, *see* Pennsylvania Dep't of Envtl. Protection, Oil & Gas Inspections – Violations – Enforcement, http://www.dep.state.pa.us/dep/deputate/minres/oilgas/OGInspectionsViolations/OGInspviol.htm.

[39] Percents, combined, may not reach 100 or may slightly exceed 100 due to rounding.

[40] *See also* description of Texas Comm'n. on Envtl. Quality violations noted in text.

	Louisiana: Haynesville Shale wells 2009-2011 158 total violations Percent of total violations[39]	Michigan: Antrim Shale wells 1999-2011 497 total violations Percent of total violations	New Mexico: tight sands and shales (not comprehensive) 2000-2011 77 total violations Percent of total violations	Texas: fractured shale wells, FY 2008-2011 72 total violations[40] Percent of total violations
equipment				
Well spacing				4.2
Fracturing-specific violations and complaints				
Fracturing			1.3	
Groundwater contamination (complaints only)			(1.2)	
Surface spill frac fluid			9.1	
Storage of waste				
Pits and tanks: construction, operation, maintenance, closure	39.3	0.2	1.3	1.4
Secondary containment	1.5	3.6		
Disposing of waste				
Land application of waste			2.6	
Improper disposal				20.8
Plugging and site closure				
Plugging		9.6		11.1
Removing equipment, filling ratholes				1.4
Well not secured if shut in		0.4		
Procedural violations: financial security, permits, tests and drills, reporting				
Financial issues (bonding, etc.)	7.4			
Permitting, plat filing, reporting	12.6		7.8	43.1
Tests and drills	0.1			1.4
Other				
Water well construction		0.2		

[41] No pressure valve on well.

We obtained data from a number of additional states that are not included in Table 2. Some, including Colorado, Ohio, Pennsylvania, and West Virginia are not included because the data are extensive and will require further efforts to fully categorize and analyze. Other states did not produce a sufficiently large sample from which to draw conclusions about the prevalence of violations at shale gas sites. From late 2009 through 2011, for example, Wyoming has had a limited amount of activity "in the Niobrara shale oil formation as well as oil exploration in tight oil sands of the Sussex, Parkman, Turner and Frontier formations, all occurring in 5 counties in the eastern half of Wyoming."[42] Twenty-five wells have been drilled and fractured in these regions, and of these wells, only one has resulted in a violation. In the Niobrara shale oil formation, "an oil spill caused by high winds blowing oil from a heater treater pressure relief valve that malfunctioned. That release was contained, remediated, and reclaimed by the operator to the satisfaction of the landowner with no fines or penalties.[43] One other potential violation has occurred in Wyoming as a result of vibroseis activity; the Oil and Gas Commission has held the operator's seismic reclamation bond "until final inspection of the remediation at sites and releases can be made."[44]

Although we have not conducted a comprehensive analysis of violations in Pennsylvania, this state has produced the largest number of violations of state environmental and oil and gas laws at shale gas sites, and examples of the types of violations are therefore important to note. In 2011, violations at Marcellus Shale sites in Pennsylvania ranged from improper casing and cementing to discharge of fracturing fluids and flowback water.[45] These led the Department of Environmental Protection to issue more than eighty notices of violation (NOVs) but did not in all cases lead to formal enforcement, such as issuance of penalties. One of the activities underlying the issuance of an NOV involved the "discharge of fracing fluid to the ground" during fracturing

[42] E-mail from Tom Doll, State Oil and Gas Supervisor, to Jeremy Schepers, June 21, 2011.

[43] *Id*.

[44] *Id*.

[45] *See, e.g.*, well permit 035-21179, Jan. 3, 2011 (discharge of ethylene glycol to well pad); well permit 115-20223, Jan. 5, 2011 (failure to case and cement to prevent migrations into fresh groundwater; defective cement job); well permit 115-20341, Feb. 28, 2011 (flowback fluids overtopping tanks spilling to ground surface beyond secondary containment); well permit 115-20228, Jan. 10, 2011 (150 barrels of treated and untreated flowback spilled from "partially open valve on blender"); well permit 035-21174, Jan. 7, 2011 ("hose with flowback on ground with discharge to soil").

(causing three violations of Pennsylvania laws).[46] Other activities leading to NOVs in Pennsylvania in 2011 included, for example, spills of pollutional substances along access roads,[47] tears in a liner on a well pad and dark staining of well site soil,[48] a failure to report defective casing,[49] rolloff containers leaking fluid onto the well pad,[50] a failure to restore a site within nine months after completing drilling,[51] and a spill of approximately 130 gallons of soap (Aqua Clear Inc. Airfoam B) when the soap "fell off a trailer while in transport."[52] The Department of Environmental Protection also has determined that several gas wells have contaminated nearby water wells, surface waters, and/or structures with gas;[53] from the data that we have obtained, we are unable to determine whether or not these wells were drilled in shale and/or were fractured.

Violations in Texas recorded by the Texas Commission on Environmental Quality (TCEQ) are not included in Table 2 because we only obtained TCEQ data for 2010-2011. We identified approximately sixteen TCEQ violations at Barnett Shale (fractured well) sites for this time period. One violation involved disposing of solids (left over after the disposal of liquid waste) in a landfill without a permit.[54] Another involved operating a salt water disposal facility without a permit,[55] and the majority of the remaining violations related to air quality (odor issues, natural gas emissions from compression stations and well pads, and opacity violations).[56] A final

[46] Well permit 081-20197, violation # 616768, July 26, 2011.
[47] Well permit 081-20271, violation # 605107, Mar. 25, 2011.
[48] Well permit 115-20250, violation # 603128, Apr. 20, 2011.
[49] Well permit 115-20284, violation # 604118, Jan. 5, 2011.
[50] Well permit 115-20635, violation # 624531, Nov. 7, 2011.
[51] Well permit 015-20296, violation # 616163, July 14, 2011.
[52] Well permit 125-24174, violation # 615820, June 13, 2011.
[53] *See* Regulation of Shale Gas Development, footnote 171 on page 50 (identifying incidents of stray gas migration from wells into underground water, basements, and other resources).
[54] Well permit. no. RN100825462 (Apr. 29, 2011 violation).
[55] Well permit no. RN105907588 (Mar. 18, 2010 violation).
[56] Spreadsheet data on file with author.

violation addressed sewage from a gas rig site that was leaking and being stored improperly without a permit.[57]

In identifying the types of violations noted in Table 2, it is important to understand which violations were minor or serious in terms of their environmental effects, as shown in Table 3. The author categorized each effect in Table 3 based on the criteria described in Figure 1. As described in Figure 1, to label each violation as procedural, minor—no effect, minor effect, substantial, or major, the author took two primary considerations into account, including the type of violation and enforcement (if any) and the nature of the environmental result, meaning the environmental medium affected and the quantity of substance that entered the medium. An agency's formal enforcement as a result of the violation, and issuance of a large penalty or an order to remediate, may indicate that the environmental effect was particularly strong. Factors other than the strength of the environmental effect also could contribute to an agency's decision to formally enforce based on a noted violation, however, including, for example, an entity's failure to take corrective action after a violation—even a mundane one—was noted, a desire to deter certain activities that will not necessarily cause environmental harm but potentially could (such as the failure to obtain a permit before constructing a site and drilling), and differing state enforcement policies. Use of the type of violation or enforcement therefore is not foolproof. For the data set that we acquired, Michigan enforcement staff often only noted violations and engaged in no enforcement activity for substantial violations such as "serious erosion" on an access road,[58] for example, while staff in Louisiana and New Mexico issued notices of violation and fines for violations that did not appear to have any environmental effect, such as a $5,000 penalty for a failure to obtain a permit (New Mexico) and $2,000 penalties for similar permitting deviations in Louisiana. This is due in part to state statutes, which dictate the types of enforcement actions that agencies may take in response to violations and the amount of the penalty that they may impose, if any.[59]

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[57] Well permit no. RN105222574, (Mar. 10, 2010 violation).

[58] April 13, 1999, violation noted for well with permit number 51521.

[59] *See, e.g.*, Railroad Comm'n of Tex., *supra* note 24, at 45 (summarizing the types of amounts of penalties that the Railroad Commission may assess for violations of various statutes, which include penalties of up to $10,000 per day

Figure 1. Methodology for Identifying the Gravity of the Environmental Effect Caused by a Violation

Gravity of environmental effect	Activity for which violation occurred	Enforcement action	Environmental factors
Procedural	--Permitting --Reporting --Testing --Financial assurance	All ranges ("violation noted" through notice of violation and/or administrative order)	No indication in violation/field notes that failure to obtain permit, report, conduct a test, or provide financial guarantee resulted in environmental damage
Minor--no effect	--Equipment failures --Pit construction, operation, and maintenance --Failure to prevent oil and gas waste --Commingling oil and gas --Site maintenance, such as moving weeds --Sign posting and hazard labels	All ranges ("violation noted" through notice of violation and/or administrative order)	No indication in field notes that violation resulted in any environmental damage
Minor effect	--Equipment failures that led to release --Pit construction, operation, and maintenance that led to release --Air pollution --Spills --Disposal	Violation noted, or NOV/administrative order paired with very small environmental effect	Small spills and improperly disposed wastes (typically less than 5 barrels of produced water or oil) that did not move offsite or otherwise suggest substantial environmental damage. Small quantities of air emissions (slightly over the daily limit, for example).
Substantial	--Equipment failures that led to release --Pit construction, operation, and maintenance that led to release --Failure to plug well twelve months after abandonment or inactivity --Air pollution --Spills --Disposal	Violation noted or NOV/administrative order + substantial environmental effect; remediation order	Medium spills and improperly disposed wastes (typically more than 5 barrels and less than 10 for produced water or oil that stayed on site). For fracturing fluid spills, any spill of more than 1 barrel was considered major.
Major	--Equipment failures that led to release --Pit construction, operation, and maintenance that led to release --Air pollution --Spills --Disposal	Violation noted or NOV/administrative order + > substantial environmental effect (or high penalty + substantial envtl. effect); remediation order + major environmental effect	Large spills or improperly disposed of wastes (typically 10 or more barrels, small to large spills that moved off site and impacted a resource (drainage ditch, wetland, etc.). Any spill of fracturing fluid > 1 barrel.

"for violations of laws, rules, orders, permits or certificates pertaining to oil and gas well safety or pollution requirements").

In light of the varied reasons for states' enforcement choices, adding the environmental result (amount of pollutant release, environmental medium affected, for example) to the type of violation helped to levelize violations across states. These environmental proxies are not perfect, however. Drawing a line at ten barrels of non-frac fluid pollutant spilled rather than twenty to identify major versus substantial spills, for example, is not rooted in scientific calculations about the toxicity of various pollutants, and the quantity spilled has different environmental effects depending on the location of the spill. While the environmental effect proxies used here sought to take into account spill location (assigning more gravity to spills that moved off site), these are only very rough measures and must be treated as such. With these limitations in mind, Table 3 summarizes the approximate percentage of violations in each state that fell into each of the categories identified for "gravity of the environmental effect."

Table 3. Gravity of Environmental Effect: Percent of Violations That Were Procedural, Were Minor and Resulted In No Environmental Effects, or Caused Minor, Substantial, or Major Effects

	Louisiana: Haynesville Shale wells 2009-2011 158 total violations Percent of total violations[60]	Michigan: Antrim Shale wells 1999-2011 497 total violations Percent of total violations	New Mexico: tight sands and shales (non-exhaustive) 2000-2011 77 total violations Percent of total violations	Texas: fractured shale wells, FY 2008-2011 72 total violations[61] Percent of total violations
Procedural	60.0	32.8	26.0	52.8
Minor—no effect	30.8	28.0	1.3	1.4
Minor effect	1.9	24.5	19.5	8.3
Substantial	7.1	14.7	41.6	29.2
Major	0.6	0.0	11.7	8.3

Detailed empirical analysis of these data and a more sophisticated toxicity-based categorization of environmental effects would be required to draw any firm conclusions about the gravity of the environmental effects represented by the violations in each state. Generally, however, the data

[60] Percents, combined, may not reach 100 or may slightly exceed 100 due to rounding.

[61] *See also* description of Texas Comm'n. on Envtl. Quality violations noted in text.

suggest that the types of violations, as well as the gravity of the environmental effects potentially associated with the violations, varied among states. The most common violations in Louisiana involved pit and tank construction and maintenance (39% of violations identified in that state), while the most common violations in Michigan were signs and labeling (33%), surface spills of produced water in New Mexico (34%),[62] and permitting in Texas (43%). Looking to the gravity of the environmental effects associated with various violations, most of the major violations identified in New Mexico involved large spills of produced water. (The percentage of spills in New Mexico as compared to other violations may not be as high as it appears here. Our data set of violations at tight sand wells is not complete, and we identified many of the violations in the State of New Mexico Oil Conservation Division's "Spills" database.)[63] One pre-2008 violation in New Mexico involved land application of produced water (quantity unidentified) accompanied by a fine of $7,500,[64] and another involved an 800-barrel spill of a hydraulic fracturing chemical.[65] The major Louisiana incident involved a discharge of saltwater into a swampy area, which required the construction of new containment facilities. An operator was using frac tanks to store produced water, and the tanks overflowed.[66] The higher percentage of substantial and major effects in New Mexico could potentially result from several factors. New Mexico's inspectors may focus more closely on environmental effects than on technical violations, such as a failure to post a sign (this may be particularly true recently as a result of the state's revised "pit rules," which require lined pits or tanks[67]). The smaller size of the data set and our reliance on New Mexico's database of spills to identify certain violations could skew the percentages. Alternatively, there could indeed be more significant problems in New Mexico.

Despite several potential major effects, Table 3 suggests that of the violations identified so far, many are procedural and represent no environmental effects; are minor with no effect—meaning

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[62] Note the discussion elsewhere in this paper explaining that we located many of the New Mexico violations within the state's spills database; a lower percentage of total violations may have involved spills than suggested here.

[63] *See* State of New Mexico Oil Conservation Division, OCD Permitting—Spills, https://wwwapps.emnrd.state.nm.us/ocd/ocdpermitting//Data/Incidents/Spills.aspx.

[64] Well permit 30-045-30652, June 2002 violation.

[65] Well permit 30-045-34815, violation # KGR0910634065, Mar. 2009 violation.

[66] Well permit 238585, settled administrative order Mar. 2009.

[67] New Mexico Admin. Code § 19.15.17 (effective 2008, currently under application for amendment).

that an inspector noted a flaw in a pit or casing job, for example, but did not note any release of a contaminant to the environment as a result of that flaw; or represent environmental minor effects, such as small releases. As noted earlier, without further data and analysis, it is not possible to know whether the majority of incidents at shale and tight sands sites are in fact procedural or minor with few environmental effects or simply represent the incidents that agencies have happened to identify.

Another important factor in understanding incidents at well sites and their potential indication of the environmental effects at well sites is the number of violations that led to enforcement actions by state agencies, such as the issuance of administrative orders and civil penalties. Table 4 provides example of some of the penalties issued by states, comparing them by the type of violation noted.

Table 4. Examples of enforcement actions by type of violation

Type of violation	Louisiana: Haynesville Shale wells 2009-2011 158 total violations	Michigan: Antrim Shale wells 1999-2011 497 total violations	New Mexico: tight sands and shales (non-exhaustive) 2000-2011 77 total violations	Texas: fractured shale wells, FY 2008-2011 72 total violations[68]
Failure to obtain permit before drilling or completing a well or producing/transporting gas	Administrative order, $1,000[69]	No permitting violations noted.	Agreed order, $23,500[70]	Agreed order, $14,500[71]
Pit/tank construction and maintenance	Order to take appropriate remedial action[72]	Violation noted, apparently no enforcement[73]	Agreed order, $5,000[74]	Agreed order, $1,000[75]

[68] *See also* description of Texas Comm'n. on Envtl. Quality violations noted in text.
[69] Well permit 240195, Jan. 7, 2010.
[70] Well permits 30-045-33820; 30-039-29748; 30-045-33476; 30-045-33495, Feb. 8, 2007.
[71] Well permits 0637567, 232848, 233600, penalty paid Nov. 4, 2008.
[72] Well permit 240662, Sept. 22, 2010.
[73] Well permit 54713, Nov. 7, 2001.
[74] Well permit 30-045-32300, Feb. 2, 2004.
[75] Well permit 0612459, check received Dec. 5, 2007.

Table 4 demonstrates that when states initiated formal enforcement action in response to a violation of an oil and gas or environmental regulation, responses in some cases varied substantially—from no enforcement to issuance of a large penalty. This may result from differing state political priorities, differing directives from legislatures (such as the power of agencies to issue penalties and the amount of the penalty that may be imposed), or varying gravity of effect. Overall, enforcement actions are sparse compared to violations noted; of the violations described in Table 2, few resulted in formal enforcement actions, with the exception of Louisiana and Texas; all of the violations noted for Louisiana and Texas resulted in the issuance of administrative orders, agreed orders, and/or penalties.[76] Although Table 2 does not include Pennsylvania data, Pennsylvania's Marcellus Shale data (available online),[77] provide further examples of violations that led to formal enforcement. Pennsylvania, like other states, did not formally enforce environmental laws in response to a number of violations notes but did impose high penalties in certain enforcement actions. Three activities at one well site, for example, including improper construction and use of surface pits, maintenance of the well site (failure to post a sign); and disposal of drill cuttings, drilling fluid, and/or NORM waste, led to a consent order and agreements and penalty of $188,000.[78] Several pre-2008 violations in New Mexico and Michigan (a time period not covered for Louisiana, and thus not directly comparable) led to formal enforcement. In New Mexico, for example, in addition to the penalties described above, one company's release of oil as a result of a frozen drain valve led to an approved compliance/remediation plan.[79] Other penalties in New Mexico resulted from operators' failing to obtain permits before drilling wells, constructing surface pits, disposing of produced water above the liner in a pit, and processing natural gas. Also prior to 2008, Michigan initiated

[76] This variation may be result from reporting differences. Louisiana and Texas may only have provided us with violations that led to enforcement actions while omitting other violations; we are communicating with agency staff to clarify the nature of the data provided.

[77] Pennsylvania Dep't of Envtl. Protection, Oil & Gas Inspections – Violations – Enforcement, http://www.dep.state.pa.us/dep/deputate/minres/oilgas/OGInspectionsViolations/OGInspviol.htm

[78] Well permit 125-24033, consent order and agreement Feb. 2011.

[79] Well permit 30-039-23605, violation # DGF0309237920, Mar.-Apr. 2003.

compliance cases for contamination of soil at a wellhead[80] and issued notices of non-compliance for failures to plug wells after production ended.[81]

Another useful data point from the violations identified in Table 2 is the number of violations that resulted from complaints; this could help to indicate whether complaints tend to validly identify environmental effects or not. A limited number of the violations in Table 2 and its addendum were noted in response to complaints. The Wyoming Oil and Gas Commission noted a seismic testing violation caused by agricultural ground disturbance after receiving a complaint, for example; the violations were immediately corrected, and no formal enforcement action ensued. Several complaints about oil or gas development activity also are on record in New Mexico and Michigan, although all of these complaints arose prior to 2008. Individuals complained of a "high-pitched whine" coming from a well site, compressor noises, weeds around a well, brine spraying from a wellhead, other wellhead leaks (venting gas), an overflowing production pit, "pungent nauseating odors," oil leaks from equipment, and improper reseeding of sites. In Michigan, complaints of compressor noise, improper reseeding, and gas leaks at the wellhead led the Michigan Department of Environmental Quality (Office of Geological Survey) to note violations, but the complaints did not lead to any formal enforcement activity. Of the small numbers of complaints received—most of which were received prior to 2008 in Michigan—the agencies noted violations but did not enforce in response to the complaints.

In Texas, far more complaints have been recorded by the Texas Commission on Environmental Quality than in other states, although few resulted in notations of violation or enforcement. Specifically, between 2010 and 2011, the agency received approximately 535 complaints about gas well development in the Barnett Shale (including gas compressor stations).[82] An additional

[80] Well permit 37853, violation May 2009.

[81] Well permits 49341 (violation Apr. 2003), 49329, 49341 (violations Aug. 2001).

[82] Spreadsheet on file with author. *See also* Barnett Shale Incident Report (V3) provided by Texas Comm'n on Envtl. Quality to Matt Peña.

two complaints were lodged with the Environmental Protection Agency. Approximately sixteen of the complaints to the TCEQ resulted in known violations.[83]

Policymakers can glean useful lessons from the data in Table 2 and from additional information about violations at shale gas sites in Pennsylvania and other states discussed in this paper. First, surface spills, improper disposal of oil and gas wastes, and problems with leaking pits or tanks are relatively common violations, which can be prevented. These relatively common incidents arose from a number of mistakes at shale gas, shale oil, or tight sands sites, ranging from allowing valves to freeze during cold weather to pouring substances into tanks with leaks in them, failing to maintain adequate dikes and other secondary containment for pits. One incident in New Mexico, in which a tank released a large quantity of frac water, was attributed to vandalism.[84] While vandalism can only be partially controlled through fencing and requirements for warning signs, many of these incidents could have been avoided by working with the oil and gas industry to ensure that careful chemical and waste handling procedures are followed. As discussed in more detail in "Regulation of Shale Gas Development," states should consider enhancing their spill prevention and control requirements and their waste storage rules to prevent these types of incidents.

An additional point of interest from Table 2 and additional information on violations is the large number of "procedural" violations that arise from oil and gas operators' failure to obtain a permit prior to drilling, submit an intent to plug, file a completion report, submit blowout prevention or other test results, or otherwise provide data to the agency. Procedural requirements are extremely important because they alert agencies to the existence of a well and the procedures followed in developing the well. With knowledge of the well, agency staff can visit the well site and ensure that substantive regulations are followed. Due to the importance of permitting and other procedural requirements, it is understandable that in addition to noting many procedural violations, state agencies tended to issue stiff penalties for a failure to follow them. In some cases, however, incidents with potentially strong environmental effects—such as large,

[83] *Id*.

[84] Permit no. 30-045-31390, incident # nBP0633238279 (Oct. 2006).

unrecovered spills of produced water or fracturing chemicals—result in few or no penalties, while a failure to submit a completion report can lead to a several thousand dollar penalty. Penalties, which are important for deterring future violations, speak strongly to the type of activity that agencies will not tolerate. Agencies should therefore reconsider their policies for pursuing penalties associated with procedural versus substantive violations and, perhaps, to work with state legislatures where statutes constrain their ability to issue stiff penalties for substantive activities with potentially strong environmental effects.

5 Conclusion

The data on violations noted by agencies, and enforcement actions taken in response to certain violations suggest that many of the environmental effects of shale gas development arise from the drilling process itself. Fracturing increases certain risks, such as surface spills of fracturing fluid, and can increase the severity of certain environmental effects (by adding new and sometimes toxic substances to the process, for example). But developing a well that is eventually fractured requires a number of other stages, including site construction and well drilling, that appear to cause the majority of environmental violations. Agencies and the media should recognize that as fracturing has enabled tight sands and shale gas development, oil and gas activity as a whole (not just fracturing) has increased. With more activity comes more potential for environmental impacts at all stages of the development process, thus necessitating responses such as better casing standards to ensure proper construction of wells, improved spill prevention programs and pit construction requirements, and other controls that can reduce the impact of expanding production.

As shown in Table 2, only 9.7 percent of oil and gas activities at shale and tight sands wells in New Mexico--of the incomplete set of violations that we identified there--were fracturing-specific. The remaining incidents that led to violations in all three states could not be clearly connected to fracturing, although some of the spills identified may potentially have occurred at the fracturing stage (although not indicated in the agency write-up). The data suggest that the tendency in the media to focus most strongly on the fracturing stage of shale gas development may not be wholly justified. Certain violations that occur during the fracturing stage potentially have more problematic environmental effects than, for example, a failure to properly maintain a produced-water pit (a non-fracturing-specific violation). Activities outside of the fracturing stage, however, should not be ignored. It appears that state agencies already recognize this, as the violations that they have noted arise at many stages of the well development process unrelated to fracturing. Agencies should ensure, however, that certain pre-fracturing development stages may require more attention in light of expanding well development and the changes that fracturing adds to the process. Inspecting sites at the casing stage to ensure that

casing is done properly, for example, becomes more important if a well is later fractured, which increases the pressure on the casing.

The rough violation data in this paper echo findings in Professor Ian Duncan's, Matt Eastin's, and Suzanne Pierce's papers, as well as those in the State Regulatory Comparison that accompanies this white paper. Specifically, the strong focus on contamination of underground water resources in the media and scientific literature could pull attention from the potentially higher risk of surface incidents. In Professor Eastin's analysis of media reports of shale gas development, the most common topics addressed in newspaper reports included contamination of ground water or well water by methane/shale gas (166 instances); ground water, well water, or aquifer contamination from fracturing (98 instances); ground water or well water contamination from shale gas in particular formations (145 instances); and well blowouts (76 instances). In online media searches, the most common shale gas development topics similarly included ground water, well water, or aquifer contamination from fracturing (83 instances) and well blowouts (79 instances). Similarly, Professor Suzanne Pierce's paper shows a strong focus on underground resources in the scientific literature. As Professor Ian Duncan notes, however, the highest risks from hydraulic fracturing may arise from surface spills of undiluted fracture fluid—not the fracturing process that occurs in the wellbore. Substantially more data are needed to confirm or deny the apparently low level of water contamination caused by fracturing so far. Indeed, the Regulatory Comparison that accompanies this paper emphasizes that states should require pre- and post-drilling analyses of nearby water sources. A nearly exclusive focus on this area of concern, however, is short-sighted. Underground water contamination—particularly from improperly cased wells that leak during drilling (or old, improperly cased wells)—is indeed a concern.[85] So, too, however, are surface effects.

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[85] *See, e.g.*, Pennsylvania Dept. of Envtl. Protection, Bureau of Oil and Gas Mgt., Stray Natural Gas Migration Associated with Oil and Gas Wells, http://www.dep.state.pa.us/dep/subject/advcoun/oil_gas/2009/Stray%20Gas%20Migration%20Cases.pdf; ., East Resources, Inc., DelCiotto No. 2, Subsurface Natural Gas Release Report Roaring Branch, McNett Township, Lycoming County, Pennsylvania 10-11 (Sept. 18, 2009) (concluding that natural gas that migrated to a spring and water wells was from natural sources and from the annulus of an improperly cased well) (October 7, 2011, response to Right-to-Know request 4400-11-170).

The limited enforcement data obtained for this paper, although not a comprehensive set, suggest that surface incidents associated with the development of oil and gas from shale and tights sands are very important. In Louisiana, nearly forty percent of violations arose from improper construction, maintenance, operation, or closure of surface pits and tanks. In Michigan, nearly a quarter of violations over more than decade of recorded violations were from surface spills, for which the contaminant was unidentified. Similarly, thirty-three percent of the incomplete set of tight gas and shale gas violations identified in New Mexico for 2000-2011 were from produced water spills. Surface violations are easier to identify, which may explain their prevalence. Inspectors cannot detect underground water contamination unless they conduct sophisticated water sampling, which the Regulatory Comparison white paper shows that many states are not doing. While the high percentage of surface incidents may result partially from ease of identification, it also may suggest that we must turn more regulatory and scientific attention to the surface—identifying the incidents at all stages of the shale gas development process that can harm soils, surface waters, underground water sources, and other important natural resources.

A final lesson from this preliminary analysis suggests that some states may need to turn their inspection and enforcement efforts toward higher-risk incidents both at the surface and underground. Although signs identifying well sites and labeling pits as containing hazardous substances are essential, the high percentage of violations noted for signage and a failure to mow weeds is somewhat surprising. Just as media reports and scientific investigations should turn more attention to risks at the surface, inspectors—who appear to focus nearly exclusively on surface incidents—should consider increasing underground water testing[86] and more closely monitoring activities such as pit and tank construction, proper casing of wells and use of blowout prevention equipment, and the safe transport of fracturing chemicals to sites and transfer of chemicals on sites.

[86] Testing water supplies near each well prior to drilling and fracturing can be time consuming and expensive. As discussed in "Regulation of Shale Gas Development," however, some states already require this. If states believe that comprehensive testing is too burdensome or could run up against legal hurdles, they could consider the alternatives discussed in this author's white paper.

Appendix A. Energy Institute Overview

The Energy Institute was established at The University of Texas at Austin to provide the State of Texas and the Nation guidance in the pursuit of a new energy paradigm. The mission of the Energy Institute is to alter the trajectory of public discourse in a positive manner, as exemplified in our credo – good policy based on good science. Implicit in the Energy Institute's formation is the idea that colleges and universities are uniquely positioned to conduct independent and impartial scientific research. This belief is reflected in the Energy Institute's assembly of multidisciplinary teams of faculty capable of addressing complex issues in a comprehensive manner. Our aim is to inject science and fact-based analysis into what is frequently a contentious dialogue and, in so doing, bring clarity to the debate that shapes public policy on these important issues.

A.1. Core Research Programs

The Energy Institute has developed a core set of major research programs designed to address some of the toughest energy challenges facing Texas and the nation. The scope of research spans the full range of energy topics – from fossil fuel issues to nuclear energy concerns and new and emerging energy technologies and resources.

Fact-based Regulation for Environmental Protection in Shale Gas Development

Hydraulic fracturing, which has been in use for decades, has the potential to unlock vast reserves of natural gas that could provide an affordable source of domestic energy for generations. Natural gas supplies unleashed through fracturing greatly enhance our nation's energy security. But much remains to be done to demonstrate that it can be developed safely and in an environmentally benign manner. Sensing the critical need to inject science into what has become a highly emotional and contentious issue, the Energy Institute has launched an independent study of hydraulic fracturing of shale for natural gas production.

A multidisciplinary team is conducting a comprehensive review of the science, policy and environmental issues surrounding fracturing. The study for the first time combines an

independent assessment of alleged groundwater contamination and seismic events ascribed to hydraulic fracturing of shale formations with a detailed analysis of the scope and effectiveness of laws and regulations related to fracturing.

The research team is investigating claims of groundwater contamination, seismic events, fugitive air emissions and other concerns associated with fracturing in states within the Barnett, Marcellus and Haynesville Shale areas. The work includes a systematic evaluation of data from scientific studies, news reports, advocacy websites, citizens' groups and other sources. The team is also interviewing local residents and other stakeholders to identify concerns and overall perceptions of shale gas development, with a focus on fracturing.

Researchers are also examining influences on current and proposed national policies relating to shale gas development and compare reported concerns about fracturing with peer-reviewed literature on recognized effects of the practice. Ultimately, the goal of this research is to promote policies and regulations grounded in science, rather than uninformed perspectives or political agendas, and to foster effective communication of fact-based regulatory approaches to shale gas development.

The Outlook for "Unconventional" in Natural Gas and Oil

As nations throughout the world grapple with how to meet an ever-increasing demand for energy, identifying sources to meet that demand is highly uncertain. What is clear, however, is that despite the continued development of renewable resources and heightened attention on issues surrounding global warming, the world as a whole will continue to rely primarily on hydrocarbon fuels to drive economic growth for the foreseeable future. However, the production of conventional hydrocarbon resources is beset with a number of serious challenges – accelerated depletion of historic sources, troubling geopolitical tensions, numerous adverse environmental impacts, and conflicting views on how to deal with irreversible climate change.

The good news is that in addition to traditional oil and natural gas resources, a number of 'unconventional' sources of hydrocarbons have emerged. To assess the prospects for these alternative sources, the Energy Institute has assembled an interdisciplinary team of University researchers to examine the most promising unconventional hydrocarbon fuels available –

including coal bed methane, shale gas and oil, oil sand, oil shale, and methane hydrate. The research team consists of faculty members or research scientists conducting state-of-the-art energy research in their respective fields.

Tthe team is addressing a wide range of issues, beginning with a summary of the resource base for each of the sources. Researchers also will examine technologies in place to exploit the resources; identify key incentives and constraints needed for future development; and provide recommendations on additional research needed to foster production. The researchers are emphasizing factors relevant to fostering or inhibiting large-scale utilization of each of the unconventional resources. Ultimately, researchers will produce a brief, clear statement of the current outlook for each of the resources studied, along with policy options available to improve the outlook for future development.

Transition from Carbon Capture and Storage (CCS) to Carbon Capture and Utilization and Storage (CCUS)

At present, there is little likelihood the private sector will adopt CO2 capture from existing coal-fired power plants unless the federal government provides sufficient funding to reduce the net cost to zero or mandates sequestration of some portion of the CO2 produced by power plants and other industrial facilities. CCUS may become an alternative approach that is more promising in the present political and budget climate. The Gulf Coast Carbon Center (GCCC) in the Bureau of Economic Geology, supported by the Energy Institute, has developed the concept of CCUS using unconventional enhanced oil recovery (EOR) as “value added” to CO2 capture and storage. Unconventional EOR is achieved through gravity dominated floods and CO2 injection below the main oil production target. The research elements involve:

- Regional and site-specific rock characterization, and oil migration history
- Improved fluid characterization; exploring for unconventional targets
- Improved techniques to balance floods to manage heterogeneity and gravity, model reservoir performance, engineer solutions and field testing
- Cost-effective public assurance of retention

Research Center for Environmental Protection at Hydrocarbon Energy Production Frontiers (REEF)

The April 2010 explosion and record oil spill in the Gulf of Mexico was a stark reminder of the risks of offshore drilling. The accident was a wake-up call for many in the industry and revealed a need for tighter regulation of deepwater exploration. Before the oil had stopped flowing from BP's Deepwater Horizon rig, the Energy Institute assembled a team of researchers to examine what had gone wrong and develop a blueprint for safely and responsibly extracting oil and natural gas from some of the most challenging regions on earth.

In collaboration with the Massachusetts Institute of Technology, the Energy Institute team has produced a comprehensive proposal – the Research Center for Environmental Protection at Hydrocarbon Energy Production Frontiers (REEF) – to identify varying approaches for managing the array of special risks and concerns associated with exploration in challenging environments, and to develop guidelines for safely transporting oil and gas once it has been extracted. The REEF team, which also includes scientists from the renowned Woods Hole Oceanographic Institution, also will produce a series of best practices for marshaling the resources necessary to rapidly respond to future accidents.

The REEF team will study regulatory and policy issues in frontier environments through a holistic approach that reflects appropriate public input and involvement. The challenge is to develop a legal and policy framework for exploration and production of hydrocarbon resources in frontier environments that achieves the right balance of environmental protection and operational flexibility.

Large-Scale Electrical Energy Storage

The generation of electricity from renewable sources, specifically the wind and the sun, has been lauded as the answer to America's need for "clean" energy. Unfortunately, the sun doesn't always shine, and the wind tends to blow hardest at night, when demand for electricity is low. Extensive use of these renewable energy sources therefore requires storage of the electricity generated over a period of at least 24 hours at base-load levels. Rechargeable conventional batteries can efficiently store the electrical energy generated by variable wind and/or radiant-

solar energy, but their capabilities are limited. Advances in technology must be made that permit inexpensive, reliable large-scale storage of electrical energy for these intermittent sources to be utilized on an on-demand basis.

Researchers at the University, in partnership with Oak Ridge National Laboratory, have formed a "virtual hub" for research in electrical energy storage. New concepts for energy storage that use a liquid rather than a solid as the battery's cathode are being investigated to enable large amounts of energy to be stored and to keep the battery cool during charge and discharge while matching the delivery of energy from intermittent sources like the wind and the sun to base load uses.

Researchers have demonstrated proof of concept for a cell in which the cathode is an aqueous solution that operates in a flowthrough mode. They have identified a solid electrolyte that increases conductivity by a factor of ten over previous oxide materials. Ideal behavior would require yet another factor of ten in conductivity. If successful, the researchers will have solved the problem of intermittent sources in a way that satisfies the requirements for utility level electrical energy storage.

Fuel from Sunlight

Hydrogen is used in large quantities in petroleum refineries to increase the octane rating of gasoline. Most of this hydrogen is produced by "reforming" natural gas using steam. However, for every four molecules of hydrogen produced in this process a molecule of carbon dioxide is produced. Given concern over carbon emissions and global climate change, research is underway for ways to produce hydrogen utilizing sunlight energy.

Sunlight can break water into its two components, hydrogen and oxygen without the need for natural gas and steam and generation of carbon dioxide emissions. Development of the materials (photocatalysts) to support the breakdown of water by sunlight efficiently has been an elusive goal for decades. Researchers at the University, supported by the Energy Institute, have developed a new photocatalyst and a new thin-film technology that in combination promise to create a new industry involving production of fuels (hydrogen) from sunlight.

Nuclear Energy and Nuclear Security

The Energy Institute, the UT Applied Research Laboratories (ARL:UT), the LBJ School of Public Affairs, and the Cockrell School of Engineering have joined forces to examine two specific nuclear areas for the Department of Defense – current security risk analysis methods and rare event considerations. Initially, the multidisciplinary team is focusing on the following:

- Reviewing current risk assessment techniques applied to misuse of nuclear materials for an illegitimate weapons program
- Using analytical techniques from game theory, optimization and simulation aimed at developing cost-effective methods for defending against such misuse
- Surveying and summarizing differing approaches to risk estimation and quantification, including scenarios involving nuclear facilities
- Comparing and contrasting methods used to structure, elicit, or model the actions of potential adversaries
- Determining policy implications associated with assessing risks and rare event threats
- Reviewing publicly available academic and policy literature on the capability and intent of potential adversaries at nuclear facilities and suitability of government assumptions about such threats

When research is completed, the team will make recommendations to further strengthen overall security risk decision making, including consideration of rare events in security risk analysis.

A.2. Complementary Energy Initiatives

Besides its core research and education programs described above, the Energy Institute is starting or supporting several additional initiatives.

Energy Research Opportunities in Cuba

For the United States, Mexico, and Cuba, the Gulf of Mexico basin represents the greatest potential source of significant new discoveries of oil and gas in the years ahead. These resources will come from challenging geologic and environmental settings in deep and ultra-deep water and at depths below the sea floor not thought possible a few decades ago. While advances in technology now allow energy companies to find and produce oil and gas in these difficult

environments, risks associated with exploiting these resources have engendered increased environmental concerns. In particular, questions have arisen over whether industry is adequately equipped to safely manage operations in frontier environments, as well as whether regulatory agencies are prepared to effectively manage development of these new resources. Cuba's entry into the picture also raises the profile of oil and gas development issues surrounding the gap, or 'doughnut hole,' in the eastern Gulf – a region where the interests of Cuba, Mexico, and the United States converge.

The Institute is discussing emerging priorities in these areas with U.S. government agencies, including the Department of State and the Department of Energy, in order to ensure that future research programs are consistent with evolving U.S. policies toward Cuba. Cuba's plans to drill exploratory wells in deep water 55 miles from the coast of Florida have added a new dimension to concerns over safe operations and environmental stewardship in the Gulf of Mexico basin. As relations between the U.S. and Cuba improve, the Energy Institute is exploring ways to forge relationships with Cuban universities and U.S. corporations seeking energy-related business opportunities in Cuba. Such mutually cooperative relationships have the potential to result in collaborative research on energy technologies, policies, and related environmental issues. The University has a long history of engagement in Latin America through research, courses, and a variety of student programs.

Energy and the "New" Europe

The face of Europe has changed dramatically since the fall of communism in 1989, with the accompanying dissolution of the Eastern Bloc, disintegration of the Soviet Union, and fragmentation of the former Yugoslavia into new states. With the expansion of NATO and enlargement of the European Union, by 10 mostly post-communist countries from Central and Eastern Europe (CEE), the dynamics of Trans-Atlantic relations has changed markedly. Energy security is one of the top priorities of all EU countries, with many of the CEE countries highly dependent on Russian oil and gas supplies.

The emergence of substantial energy resources in the CEE countries – with the advent of hydraulic fracturing of shale to produce natural gas – the geopolitical frontier between energy

producers and consumers has shifted dramatically. The growing importance of shale gas has the potential to make the CEE countries self-sufficient in energy supplies, free them from dependence on Russian supplies and capable of becoming energy exporters, with concomitant financial and political power. Current natural gas finds in Poland, for example, give that country at least 300 years of supply, based on 2009 usage. The geopolitical orientation of this region is changing, with profound consequences not only for Europe, but for global political relationships.

Under Energy Institute sponsorship, the University of Texas at Austin and Masaryk University in Brno are exploring this sea-change in orientation, both geographical and intellectual, through collaborative interdisciplinary research and teaching. The wide scope of mutual interests between the two institutions presents an opportunity to establish a wider framework of cooperation, including respective partner institutions and academic and research institutes with various fields of expertise.

The UT Energy Poll

Consumers' views of energy are in a perpetual state of flux, influenced by how much they pay for gasoline and for heating and cooling their homes, as well as by catastrophic events from across the world (such as Fukushima) or controversial issues closer to home (hydraulic fracturing of shale). Public perceptions of energy issues also shape the formation of public policy and affect voter preferences for officeholders at all levels of government. As the growing demand for energy continues to stretch available resources, perception of the risks and rewards associated with various energy sources take on even greater importance.

To better understand consumers' views and how they affect consumption patterns, investment in new technologies and other issues, the Energy Management & Innovation Center (EMIC) at the University, with support of the Energy Institute, has launched the UT Energy Poll. The survey has been designed to provide an impartial, authoritative source of public opinion on energy issues, generating data to inform and guide debate, investment planning and policy development.

The UT Energy Poll tests consumers' views in a variety of areas, including: 1) the extent and nature of America's energy challenges; 2) an assessment of national priorities related to energy investment and consumption; 3) the role of government and industry in addressing energy

problems; 4) support for options intended to resolve energy challenges; and 5) sources of trustworthy information on energy issues. The poll, which is administered online to 2,000 consumers, consists of 100 questions and lasts no more than 20 minutes. It includes four sets of questions that:

1. Gauge public perceptions of current and future energy prices and how these prices affect consumers individually and the economy as a whole
2. Assess the public's satisfaction with the work of government, business, energy industry leaders, academics and public interest groups to address energy issues
3. Test consumer views regarding knowledge of and interest in energy issues, potential trade-offs related to the production and consumption of varying sources of energy, trustworthy sources of information on energy issues, voting behavior, social and cultural sources that influence energy usage, and the future of energy.
4. Focus on a special issue unique to each version of the survey; potential topics include energy and job creation, climate change, renewable energy, technology and energy finance.

An academic advisory panel reviews the survey findings prior to their release, and continues to guide the strategy, positioning, and roll-out of future surveys and findings. In addition, representatives from the Environmental Defense Fund, the Natural Resources Defense Council, and the Nature Conservancy have pledged to review poll questions and ensure the poll's objectivity.

UT Office of Sustainability

The President of the University has established a Sustainability Steering Committee composed of faculty, staff and students. The committee is charged with setting strategic direction and the pursuit of specific tasks designed to expand and promote the university's sustainability portfolio. The Energy Institute supports UT's Office with participation in the Sustainability Steering Committee.

The Office of Sustainability encourages broad critical thinking with respect to our interactions with the environment – our needs and the effect of our actions on the environment; our sense of humanity and how the way we live affects others; and how we define and perceive return-on-investment. It coordinates and communicates existing efforts, promotes new initiatives, and

encourages the conversation about the pursuit of sustainability. The Office works to ensure the University remains a leader in producing research and scholars that help shape a more sustainable global future. It takes a holistic approach to initiatives, focusing on solutions that consider the long-term effects of our actions and their impact on future generations.

A.3. Energy Education

Along with its primary mission of facilitating research that provides science-based solutions to pressing energy challenges, the Energy Institute is deeply committed to developing interdisciplinary certificate and degree programs in energy at the University. The Institute is currently most active in two areas, both of which are designed to broaden the educational experience of students in energy-related fields.

First, the Institute sponsors the UT Energy Symposium to provide a platform for students and faculty to interact on a wide range of topical energy-related issues. The Symposium was created in response to a desire among students for credible information on energy issues. The weekly forum is intended to provide students the opportunity to glean valuable information from experts representing diverse perspectives in an open, informal setting. Throughout the semester, experts from industry, government or academia present their perspectives on technological, policy, regulatory and market aspects of the week's topic. Lecturers also discuss how the designated topic relates to the future of energy on a global scale. The lecture series is open to the public.

In the second area, the Energy Institute is leading an effort to establish a Graduate Portfolio Program in Energy Studies a new, interdisciplinary graduate program designed to supplement graduate students' course knowledge and provide practical knowledge to those who may pursue professional careers in energy. The Program will integrate existing resources throughout the university and synthesize course study with practical application to augment the breadth and depth of graduate student knowledge in various energy fields. Program requirements call for graduate courses in energy related fields with an emphasis on classwork outside their degree programs. Students must also complete a research project and report their results at a professional meeting or an on-campus event.

A.4. Advisory Council

The overall mission and direction of the Energy Institute comes from an Advisory Council whose members comprise senior professionals and executives from a cross-section of organizations:

Dr. Samuel Bodman, Chairman. Former Secretary, U.S. Department of Energy; Member, Board of Directors, DuPont, the Hess Corporation, and the AES Corporation.

Dr. Bernard Bigot. Chairman of the Atomic Energy Commission of France; Chairman and Chief Executive Officer of the Alternative Energies and Atomic Energy Commission; President of "la Fondation Internationale de la Maison de la Chimie

Ernest H. Cockrell. Chairman, Cockrell Interests Inc.; President and Director, Cockrell Foundation; Chairman and Director, Welch Foundation

Linda Zarda Cook. Director, Boeing Company, Cargill, Inc.; Executive Director, Royal Dutch Shell plc (Retired)

Kenneth R. Dickenson. Chairman, Texas Association of Engineering Boards; Member, Development Board, University of Texas at Dallas; Co-Chairman, Industrial Advisory Board, School of Engineering and Computer Sciences, University of Texas at Dallas; Vice Chairman of Engineering Advisory Board, University of Texas at Austin; Board of Trustees, House Institute, Los Angeles; Board of Trustees, Center for American and International Law; Senior Associate, Sustainable Development Corporation, California

Donald Louis Evans. Former Secretary, U.S. Department of Energy; Chairman, Energy Future Holdings; Senior Partner, Quintana Energy Partners; Chairman, George W. Bush Presidential Center

Randy A. Fouch. Chairman, President and Chief Executive Officer, Laredo Petroleum, Inc.

Robert W. Fri. Visiting Scholar, Resources for the Future

Henry Groppe, Jr. Vice Chairman Founding Partner, Groppe, Long & Littell

Ronald Hulme. Chief Executive Officer, Carlson Capital

Fred Krupp. President of Environmental Defense fund (represented by James D. Marston - Director of the Texas Regional Office, and Director of the National Energy Program)

James J. Mulva. Chief Executive Officer, ConocoPhillip

Jack P. Randall. Co-founder and Managing Partner, Jefferies Randall & Dewey Inc.; Director XTO Energy

Shahid Ullah. Chief Operating Officer and Member of the Executive Board, Afren PLC; Member, Engineering Advisory Board, The University of Texas at Austin

Dr. Deborah L. Wince-Smith. President and CEO, Council on Competitiveness; of Director, NASDAQ-OMX, Inc.; Member, Oversight Board of the Internal Revenue Service; Member, U.S. Department of State's Advisory Committee on International Economic Policy; former Chair, Secretary of Commerce's Advisory Committee on Strengthening America's Communities; Member, University of Chicago's Board of Governors for Argonne National Laboratory; Member, Board of Directors, Albert Shanker Institute.

Also included in the Advisory Council as Ex Officio Members are the Deans and Directors of the participating schools and research units of the University:

- Cockrell School of Engineering
- McCombs School of Business
- LBJ School of Public Affairs
- Jackson School of Geosciences
- College of Natural Sciences
- School of Law
- Bureau of Economic Geology

A.5. Faculty Associates and Energy Institute Staff

Each University dean having interests relevant to the Institute has named a faculty representative to serve as a member of the Faculty Associates to help integrate the extensive campus resources into cohesive energy security programs. The organization is an outreach network to the research and instructional resources of the University's schools and colleges. Faculty Associates of the Institute represent the following entities as the University:

- School of Architecture
- McCombs School of Business
- College of Communication
- Cockrell School of Engineering
- Jackson School of Geosciences
- School of Law
- College of Liberal Arts
- College of Natural Science
- LBJ School of Public Affairs

The Energy Institute staff comprise senior energy professionals who have held high-level positions at the national level:

Raymond L. Orbach, Ph.D., Director.

Prior to his current position, Dr. Orbach served as the first Under Secretary for Science at the U.S. Department of Energy (DOE). His primary responsibility was to serve as chief scientist for DOE and advise the Secretary of Energy on a variety of topics. He was responsible for leading the Department's implementation of the American Competitiveness Initiative, designed to help drive continued U.S. economic growth. He was also responsible for leading the Department's efforts to transfer technologies from DOE national laboratories and facilities to the global marketplace, serving as Chair of the Technology Transfer Policy Board. Prior to and concurrent with serving as Under Secretary for Science, Dr. Orbach served as the Director of the Office of Science, which is the third largest Federal sponsor of basic research and primary supporter of the physical sciences in the United States.

Before his DOE positions, Dr. Orbach was Chancellor of the University of California (UC), Riverside. Under his leadership, UC Riverside doubled in size, achieved national and international recognition in research, and led the University of California in diversity and educational opportunity. Dr. Orbach began his academic career as a postdoctoral fellow at Oxford University and became an assistant professor of applied physics at Harvard University He later joined the faculty of the University of California, Los Angeles (UCLA), and served as the Provost of the College of Letters and Science at UCLA. Dr. Orbach's research in theoretical and experimental physics has resulted in the publication of more than 240 scientific articles.

Dr. Orbach received his Bachelor of Science degree in Physics from the California Institute of Technology in 1956. He received his Ph.D. degree in Physics from the University of California, Berkeley, in 1960 and was elected to Phi Beta Kappa.

Charlie Cooke, Deputy Director

Charlie Cooke has been involved in energy policy and legislation in Washington for more than 35 years. Prior to joining the Energy Institute, he was Assistant Vice Chancellor for Federal Relations at The University of Texas System in Washington, where he had responsibility for the support of the System's nine academic institutions on federal issues of interest to the campuses. Before his University position, he was a Professional Staff Member with the U.S. House Science

and Technology Committee and previously had oversight responsibilities for the energy research programs at the Department of Energy. The Committee was focused on DOE Big Science programs, including the Superconducting Super Collider.

Prior to his House Committee responsibilities, Mr. Cook represented Southern California Edison Company in Washington where he worked primarily on industry restructuring, tax, electric transportation and telecommunications issues. Previously he was with a consulting firm that represented Texas oil and gas, banking and ranching interests in Washington and Austin. He also served as an assistant to a member of the former Federal Power Commission (now the Federal Energy Regulatory Commission). Prior to moving to Washington he served as energy advisor to two Texas Governors, Preston Smith and Dolph Briscoe, and worked for the Texas Legislature in the State Senate.

Charles G. (Chip) Groat, Ph.D., Associate Director

Charles G. (Chip) Groat is Associate Director of the Energy Institute, Director of the Center for International Energy and Environmental Policy, and Director and Graduate Advisor of the Energy and Earth Resources Graduate Program. His current interests focus on advancing the role of science and engineering in shaping policy and informing decisions, and on ways to increase the integration of the science disciplines as a means of improving the understanding of complex resource and environmental systems. He holds the John A. and Katherine G. Jackson Chair in Energy and Mineral Resources in the Department of Geological Sciences, Jackson School of Geosciences, and is Professor, LBJ School of Public Affairs at The University of Texas at Austin. He served as interim dean of the Jackson School of Geosciences at UT from July 2008 to August 2009.

He assumed these positions at The University of Texas at Austin after serving 6½ years as Director of the U.S. Geological Survey, having been appointed by President Clinton and retained by President Bush. Prior to his position with the U.S. Geological Survey, he was Associate Vice President for Research and Sponsored Projects at The University of Texas at El Paso following a term as Director of the Center for Environmental Resource Management and Professor of Geological Sciences there. His previous experience includes the following:

- Associate Director and Acting Director of the Bureau of Economic Geology and Associate Professor of Geological Sciences at The University of Texas at Austin
- Chairman of the Department of Geological Sciences at The University of Texas at El Paso; State Geologist and Director of the Louisiana Geological Survey
- Assistant to the Secretary of the Louisiana Department of Natural Resources administering the Coastal Zone Management and Coastal Protection programs
- Professor of Geology and Geophysics
- Director of the Center for Coastal, Energy and Environmental Resources at Louisiana State University; and Executive Director of the American Geological Institute.

Dr. Groat has been a member of the National Research Council Board on Earth Sciences and Resources and the Outer Continental Shelf Policy Board. He is a past President of the Association of American State Geologists and of the Energy Minerals Division and Division of Environmental Geosciences of the American Association of Petroleum Geologists. His degrees in geology are from the University of Rochester (A.B.), University of Massachusetts (M.S.), and The University of Texas at Austin (Ph.D.)

Dale E. Klein, Ph.D., Associate Director

Dr. Dale Klein rejoined The University of Texas at Austin in April, 2010 after serving almost 8½ years as a Presidential Appointee. He currently is a Professor of Mechanical Engineering, Associate Vice President for Research, and Associate Director of the Energy Institute. Dr. Klein was appointed Chairman of the U.S. Nuclear Regulatory Commission by President George W. Bush and served in that role from July 1, 2006, to May 13, 2009. From then until March 30, 2010 he served as a Commissioner. As Chairman and Commissioner, he believed that the NRC must continue to ensure the safety and security of current operating reactors as it also prepared to receive more than 30 license applications for new reactors.

Before joining the NRC, Dr. Klein served as the Assistant to the Secretary of Defense for Nuclear and Chemical and Biological Defense Programs. He was appointed to this position by President George W. Bush and confirmed by the Senate on Nov. 8, 2001. In this position, he served as the principal staff assistant and advisor to the Secretary of Defense, Deputy Secretary

of Defense, and the Under Secretary of Defense for Acquisition and Technology for policy and planning matters related to nuclear weapons and nuclear, chemical, and biological defense.

Previously, Dr. Klein served as the Vice-Chancellor for Special Engineering Programs at the University of Texas System and as a professor in the Department of Mechanical Engineering (Nuclear Program) at the University of Texas at Austin. During his tenure at the University, Dr. Klein has been Director of the Nuclear Engineering Teaching Laboratory, Deputy Director of the Center for Energy Studies, and Associate Dean for Research and Administration in the College of Engineering. He has published more than 100 technical papers and reports, and co-edited one book. He has made more than 400 presentations on energy and has written numerous technical editorials on energy issues that have been published in major newspapers throughout the United States. He holds a bachelor's and master's degree in mechanical engineering and a doctorate in nuclear engineering, all from the University of Missouri-Columbia.

Thomas W. Grimshaw, Ph.D., Research Fellow

Dr. Grimshaw's professional interests are in energy policy, with emphasis on emerging energy technologies and resources. He is particularly interested in the intriguing case of cold fusion, with its potential as a major – but controversial – energy source. He is currently co-principal investigator for two projects at the Energy Institute of The University of Texas at Austin. One of the projects is an assessment of the outlook for unconventional natural gas and oil resources. The other project is developing the basis for science-based regulation for of shale gas operations. Dr. Grimshaw received the masters degree (mid-career option) at the LBJ School of Public Affairs and subsequently served as adjunct faculty. He was co-instructor for two policy research projects, both of which focused on energy policy and emerging technologies. He is currently leading an initiative at UT's Center for International Energy and Environmental Policy for dealing with secondary impacts of broad deployment of cold fusion as a major energy source.

Dr. Grimshaw received the master's degree (mid-career option) at the LBJ School of Public Affairs and subsequently served as adjunct faculty. He was co-instructor for two policy research projects, both of which focused on energy policy and emerging technologies. Dr. Grimshaw has taught courses on energy and environmental policy as adjunct faculty at the LBJ School.

Before shifting to energy policy, Dr. Grimshaw had a lengthy career in environmental protection and consulting services. His dissertation for the PhD in geology was on environmental care and geologic hazards in growing urban areas. He worked primarily as a technical consultant, providing professional environmental services for municipal infrastructure, commercial facilities, and government installations. Much of his environmental work was for energy-related facilities, including oilfield waste sites, coal mines, petroleum refineries, coal-fired power plants, and synthetic fuels (coal gasification and liquefaction) plants. Dr. Grimshaw has also held the position of Associate Director for Environmental Programs at the UT's Bureau of Economic Geology and has taught courses on environmental geology at the community college level. As adjunct faculty at the LBJ School, he was also instructor for a course in environmental policy.

In addition to the mid-career M.P.Aff. degree, Dr. Grimshaw has a BS in Geological Engineering from the South Dakota School of Mines and Technology and an MA and PhD in Geology from The University of Texas at Austin.

Appendix B. Project Team

Assessment of fact-based regulations for shale gas development requires a broad range of perspectives from a number of disciplines. The assessment has been accomplished by a multidisciplinary team of experts who are well recognized for their energy-related work in their respective fields. The team consists of representatives from six organizations at The University of Texas at Austin:

- Energy Institute
- Cockrell School of Engineering
- Jackson School of Geosciences
- UT Bureau of Economic Geology
- UT School of Communications
- University of Tulsa College of Law

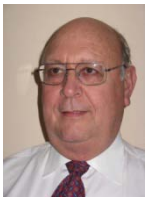
The Environmental Defense Fund reviewed and provided comments on the White Papers and draft and final reports. Brief biographical summaries of the team members are provided below.

B.1 Principal Investigator and Co-Investigator

Charles G. Groat, PhD, Associate Director, Energy Institute

Dr. Groat's interests focus on advancing the role of science and engineering in shaping policy and informing decisions. He is Director of the Center for International Energy and Environmental Policy (CIEEP) at the Jackson School of Geosciences. CIEEP is chartered as a dedicated policy center in one of the University's longstanding areas of leadership – energy development and its confluence with the environment. Prior to these positions, Dr. Groat served for 6½ years as Director of the U.S. Geological Survey, having been appointed by President Clinton and retained by President Bush. He has been a member of the National Research Council Board on Earth Sciences and Resources and the Outer Continental Shelf Policy Board. He is a past President of the Association of American State Geologists and of the Energy Minerals Division of American Association of Petroleum Geologists. His degrees are in geology from the University of Rochester (AB), University of Massachusetts (MS), and The University of Texas at Austin (PhD).

Thomas W. Grimshaw, PhD, Research Fellow, Energy Institute



Dr. Grimshaw's professional interests are in energy policy, with emphasis on emerging energy technologies and resources. He is particularly interested in the intriguing case of cold fusion, with its potential as a major – but controversial – energy source. He is currently co-principal investigator for two projects at the Energy Institute of The University of Texas at Austin. One of the projects is an assessment of the outlook for unconventional natural gas and oil resources. The other project is developing the basis for science-based regulation for of shale gas operations. Dr. Grimshaw received the master's degree (mid-career option) at the LBJ School of Public Affairs and subsequently served as adjunct faculty. He was co-instructor for two policy research projects, both of which focused on energy policy and emerging technologies. Dr. Grimshaw has also taught courses on energy and environmental policy at the LBJ School. In addition to the Master of Public Affairs degree, he has a BS in Geological Engineering from the South Dakota School of Mines and Technology and an MA and PhD in Geology from The University of Texas at Austin.

B.2 Senior Participants: White Paper Authors

Scott Anderson, JD, Environmental Defense Fund

Scott Anderson is a Senior Policy Advisor for Environmental Defense Fund's (EDF) Energy Program. Since 2005, he has served as EDF's point person on policies relating to natural gas development and to the geological sequestration of carbon dioxide. Mr. Anderson works on a broad array of legislative and regulatory issues, and participates in stakeholder groups focused on reducing the environmental footprint of natural gas operations. Mr. Anderson spent many years in the oil and gas industry prior to joining Environmental Defense Fund. He is the former Executive Vice President and General Counsel of the Texas Independent Producers and Royalty Owners Association (TIPRO). Mr. Anderson was the long-time Secretary of the LIAISON Committee of Cooperating Oil and Gas Associations and was previously a member of the governing Council of the State Bar of Texas Oil, Gas and Mineral Law Section.

Ian Duncan, PhD, Bureau of Economic Geology

Dr. Duncan is Program Director at the Bureau of Economic Geology (BEG) and conducts research at the BEG's Gulf Coast Carbon Center, whose mission is to apply its technical and educational resources to implement geologic storage of anthropogenic carbon dioxide on an aggressive time scale. Its a focus is on a region where large-scale reduction of atmospheric releases is needed and short term action is possible. Dr. Duncan's areas of expertise are carbon sequestration, integration of carbon capture into enhanced oil recovery, clean coal technologies, remote sensing, and environmental geology. He is currently serving as Principal Investigator for a U.S. Department of Energy project to develop a comprehensive risk assessment framework for geologic storage of carbon dioxide. He has given testimony to Congressional committees on three occasions related to carbon dioxide sequestration and application to enhanced oil recovery. Dr. Duncan has a BA in Earth Sciences from Macquarrie University in Sydney and a PhD in Geological Sciences at the University of British Columbia.

Matt Eastin, PhD, School of Communications

Dr. Matthew Eastin's research focuses on new media behavior. From this perspective, he has investigated information processing as well as the social and psychological factors associated with game play, new media adoption, e-commerce, e-health, and organizational use. His research utilizes information processing as a central mechanism to new media experiences and knowledge acquisition. Dr. Eastin's research has been published in a number of prestigious peer-reviewed journals, including the Journal of Communication, Communication Research, Journal of Broadcasting & Electronic Media, CyberPsychology & Behavior, Journal of Computer-Mediated Communication, and Computers in Human Behavior. He received his PhD in Mass Media from Michigan State University and was Assistant Professor for Communication at Ohio State University for several years prior to his current position as Associate Professor of Advertising.

Hannah Wiseman, JD, University of Tulsa College of Law

Ms. Wiseman is an Assistant Professor at the University of Tulsa College of Law, where she teaches Environmental Law, Energy Law, and Property Law. Her scholarship addresses issues at the intersection of land use, energy, and environmental law. She also regularly writes and lectures about the regulation of hydraulic fracturing. Professor Wiseman's articles have been published in the Georgetown Law Journal, Columbia Law Review *Sidebar*, South Carolina Law Review, and several others. After working in ICF Consulting's Climate and Atmosphere Policy Practice, Professor Wiseman received her J.D. from Yale Law School, where she was a managing editor of the Yale Journal on Regulation. Professor Wiseman clerked for the Honorable Patrick Higginbotham on the United States Court of Appeals for the Fifth Circuit and then spent two years as a visiting assistant professor at the University of Texas School of Law, where she taught Environmental Law, Energy Law, Electricity Law, and Land Use & Environmental Law. She is a member of the Texas Bar.