ENERGY AND RESOURCES GROUP, UNIVERSITY OF CALIFORNIA-BERKELEY

An Analysis of the Environmental Impacts of the Extraction of Shale Gas and Oil in the United States with Applications to Mexico

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July 15, 2015

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1 Introduction

The advent of hydraulic fracturing combined with horizontal drilling in the United States has dramatically changed the oil and gas industry. Since 2008, The United States has increased its production of oil and natural gas by almost 85 billion cubic meters/year and crude oil by over 3 million barrels per day (US EIA 2014a). Baker Hughes' horizontal/directional drilling rig count can be used to see the scale of hydraulic fracturing in the United States. Figure 1 shows how this industry took off roughly around 2005 and accordingly, production volumes increased significantly. This is evidenced by the reversal of the U.S.'s decline in production shown in figure 2.

Figure 1: Baker Hughes Rig Count, (Baker Hughes 2014)

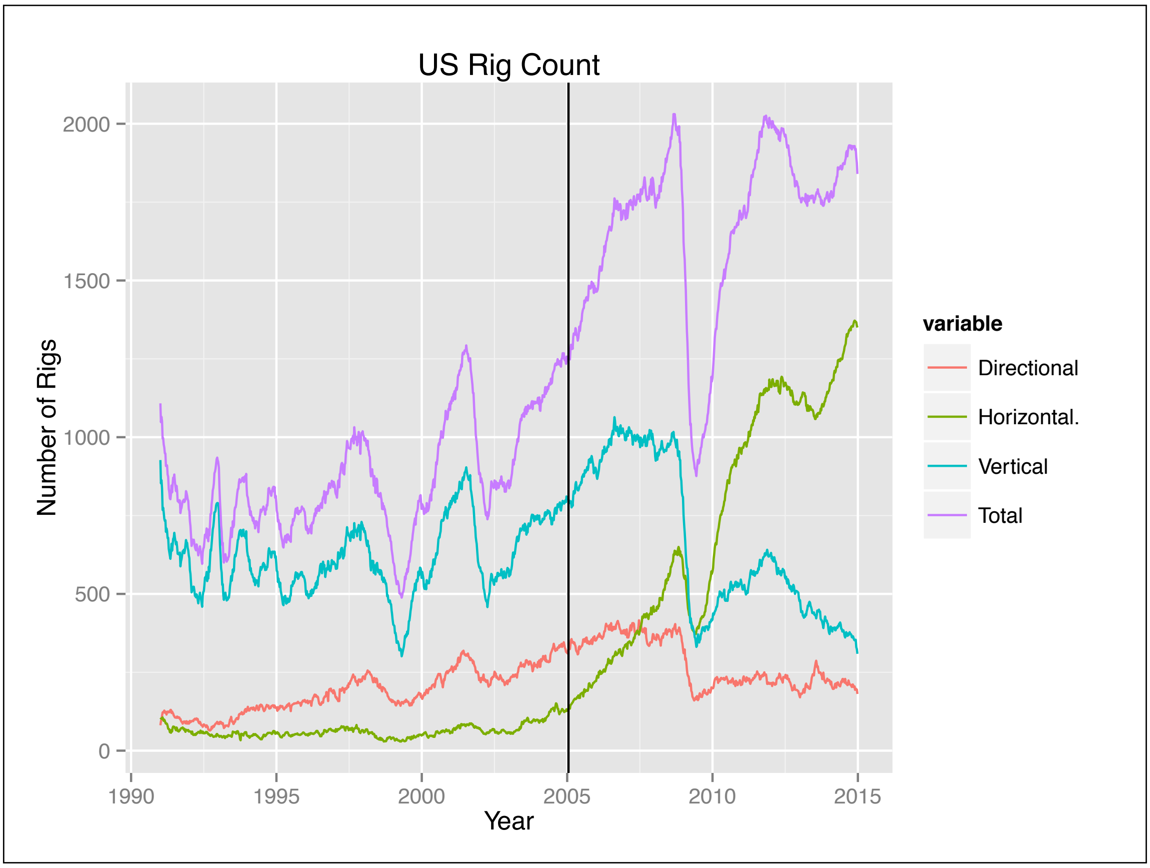
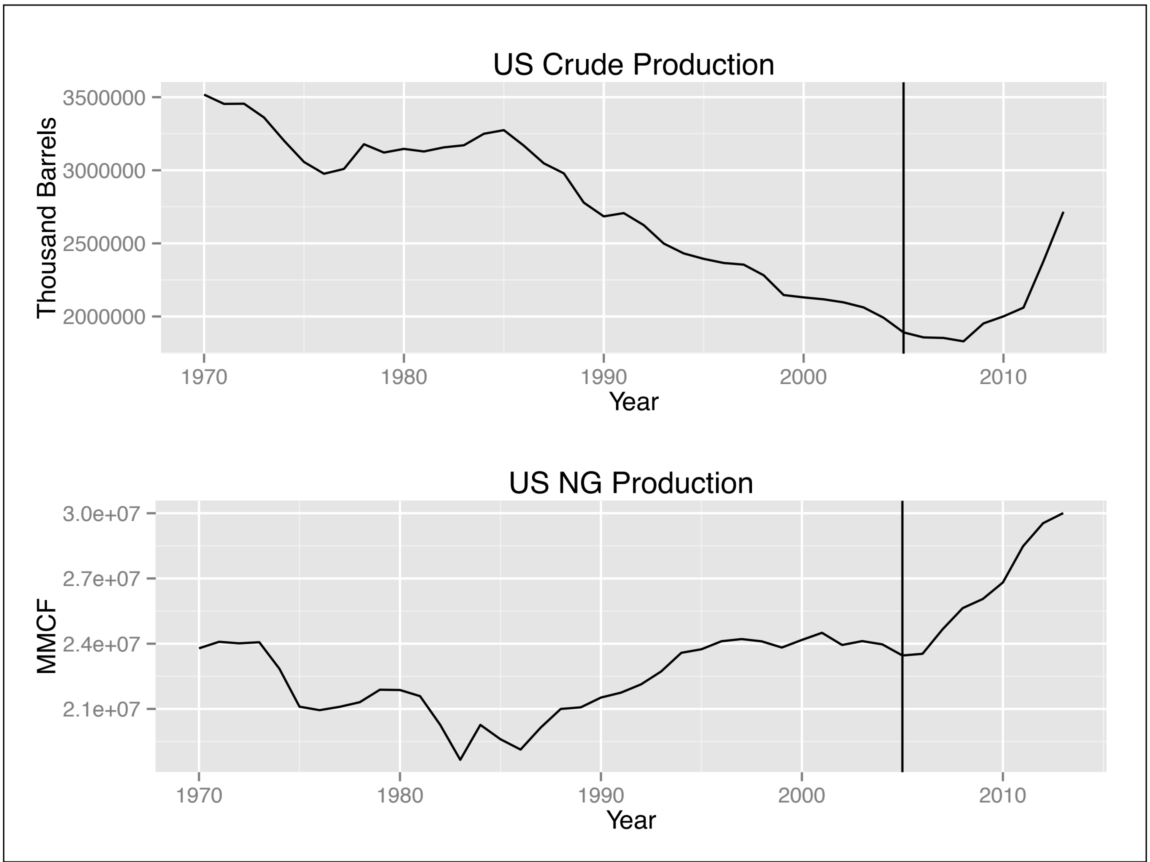


Figure 2: US Oil and Natural Gas (NG) Production, (US EIA 2014a)



The marked rise in drilling activity along with new drilling methods meant that regulations were slow to catch up (Brady and Crannell 2012). Consequently, much controversy has arisen around the question of whether the previous oil and gas regulatory structure was sufficient to protect public health. (Alan Krupnick, Hal Gordon et al. 2013).

Regulatory agencies have had to proceed in the absence of information and data. While the process of hydraulic fracturing has been around since the 1940s, the scale and magnitude of development experienced since 2005 was unlike anything seen before (US EIA 2014a). The question regulators had to answer was: did hydraulic fracturing require new and updated regulations or were historical regulatory methods sufficient to minimize human and environmental impacts?

The simplest answer was no, previous rules and regulations were not sufficient for this purpose. However, given that the federal government largely avoided the question, it was left up to states to fill this gap and decide how to make the required changes. This resulted in different regulatory approaches for hydraulic fracturing across the country.

Industry and operators have the greatest information regarding the hydraulic fracturing process. However they are not always willing to disclose it, given trade secret concerns and the competitive benefits they derive from practices. Trying to address this information asymmetry, academic and government literature addressing hydraulic fracturing processes has been accumulating over the years.

This report intends to shed light on the knowns and unknowns regarding the impacts of hydraulic fracturing. It broadly explains the environmental issues associated with hydraulic fracturing, includes relevant studies and literature, and explores how different communities in the United States have attempted to address this issue through regulation.

In addition, this report will include examples of the most relevant state regulations, American Petroleum Institute (API) standards for development, as well as the relevant State Review on Oil and Natural Gas Environmental Regulations (STRONGER) guidelines. It is not an environmental impact statement (EIS), but California and New York have statewide reports that are very helpful.

These regulations will be highlighted in gray.

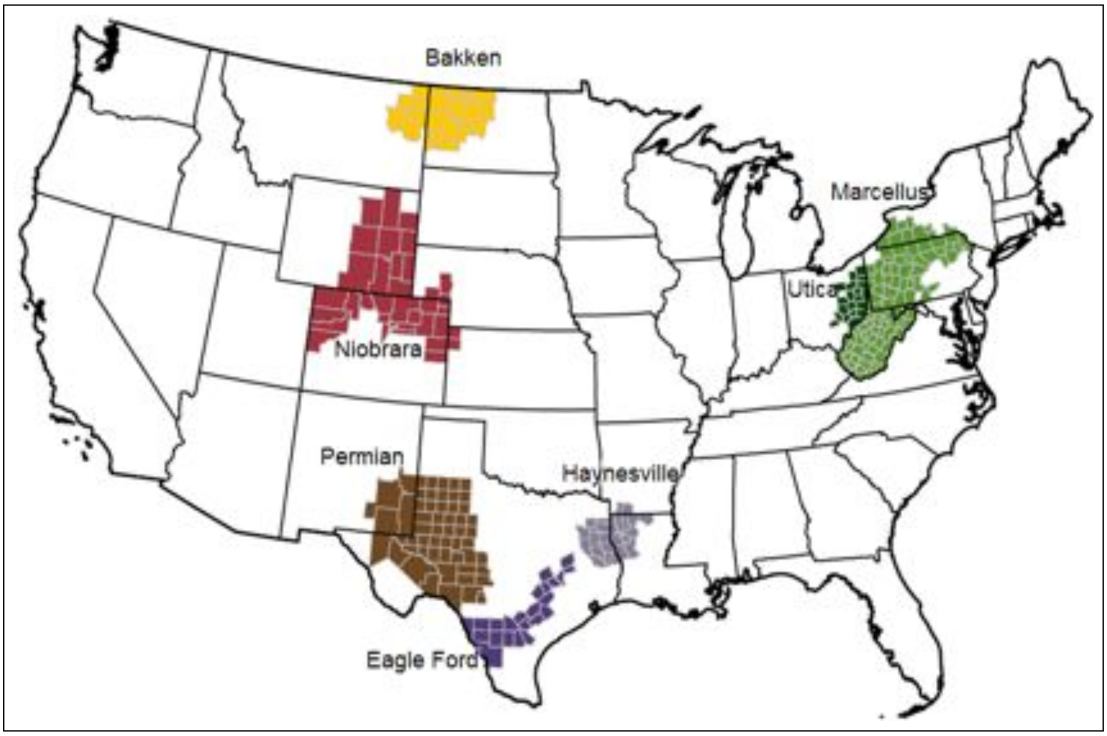
The format of the report is as follows: aggregated literature is presented at the beginning of the relevant section, followed by a brief summary, analysis, and any relevant conclusions and regulations.

2 Hydraulic Fracturing Overview

In order to best put the environmental impacts in context, this report will present an overview of the current state of hydraulic fracturing in the United States. It will cover the major active areas as well as give a brief overview to the actual hydraulic fracturing process.

According to the US energy Information Agency (EIA) from 2011-2013 seven regions accounted for 95% of the total growth in domestic oil and natural gas production in the United States. These areas are shown below in figure 3 and are spread across twelve states, each of which has its particular political relationship with its oil and gas industry and its own regulatory framework to address it. In addition to this, each play is geologically distinct and requires different extraction and management techniques (Veil and Clark 2011).

Figure 3: Most Active Shale Plays in the United States, (US EIA 2014b)



There are millions of oil and gas wells in these plays, of which around 2 million have already been hydraulically fractured. According to the U.S. Department of Energy (DOE), 95% of all new wells have been hydraulically fractured and these wells accounted for 43% of total U.S. oil production and 67% of total natural gas production in 2012 (U.S. Department of Energy 2012). It is estimated that this number has increased since then, however a significant drop in oil prices in 2014 may slow this growth.

The average lifetime of a shale oil or gas well varies highly. As an example, the ultimate estimated recovery (EUR) for a natural gas well can range from a dry hole (i.e. 0) to 10+ billion cubic feet (BCF) for a single well. However, in the lower 48 U.S. states the average EUR is roughly 1 BCF per well (US EIA 2011).

The total lifetime of each well is determined by adding the time needed to drill a horizontal well (roughly 4-5 weeks), to the time it takes for the well to reach uneconomical levels of production (NYSDEC 2011). The lifetime is therefore highly dependent on oil and natural gas prices as well as technology advances, this two uncertain factors make the lifetime estimates vary wildly. Common estimates range from 30-year optimistic lifetimes (O'Sullivan and Paltsev 2012) to more conservative estimates of 5-8 years until the wells reach "stripper well" status (less than 10bbl/day of production) (Hughes 2013).

This report will now explain the basics of hydraulic fracturing and highlight the key elements of the process where environmental and health issues arise. Ultimately, the purpose of hydraulic fracturing is to increase the permeability of the source rock to get oil and gas to flow through it. To do this, most operations follow these basic steps: permitting, site preparation, drilling, hydraulic fracturing, completion, and post-completion.

2.1 Permitting Process

The first step for conducting hydraulic fracturing activities is to acquire a permit to drill and build infrastructure. Every state requires permits to be filed with the state regulatory agency to create a record and to ensure that the drilling plans meet the required regulatory codes. These approvals should be used to ensure compliance with regulations and allow for the regulatory agency to keep track of bad operators (State Review of Oil and Natural Gas Environmental Regulations 2014). The permitting process varies from state to state, but as an example this report will look at Colorado's permitting process (Colorado Oil and Gas Conservation Commission 2013).

To receive approval to drill for oil and gas in Colorado, an operation must follow the following steps:

- Register for Oil and Gas Operations - operators must register with the local regulatory agency, provide contact information, and prove that the company has financial solvency. Financial solvency consists of a liability insurance of $1,000,000 and bonds ranging from $10,000 to $100,000 depending on scale of the development.[1]
- Apply for a Drilling Permit - operators must submit location data and conduct a location specific environmental impact assessment then wait for approval.
- Submit a Drilling Completion Report - operators must submit an engineering report regarding the drilling data, total depth, cementing test results, and verify that this matches the information described in the application permit.
- Submit a Well Abandonment Report - operators must submit engineering report of well plugging and abandonment.
- Submit Monthly Operations Reports - operators are required to report every well and every well completion each month from the day the well is spud for the entire lifetime of the well including one month as plugged. Important information, such as the status of the well, its production volume,

[1]These numbers vary greatly by state and have been criticized as being insufficient to ensure financial coverage of environmental damage (Dutzik and Davis 2013)

and the number of active days must be reported each month for each completed formation.

If the permit to drill and the environmental impact statement are both approved then the operator can begin site preparation.

2.2 Site Preparation

The site is selected based on the perceived geological conditions and once the geological conditions are determined, exploratory wells can be drilled. During site preparation, storage tanks are installed, water and drilling mud pits are dug, containment dykes are made, and roads and pipelines are built (Ground Water Protection Council 2009). Depending on the conditions of the selected location, the area might need to be cleared, leveled, and given road access. Berms have to be built taking safety precautions. The exact area required varies and is explored in section 5.

The area required per well-pad decreases as more wells are drilled due to the fact that new well-pads can rely on previous infrastructure, nevertheless it is worth considering a minimum spacing distance between well pads of one per 2.6 square kilometers. Figure 4 from (EcoFlight 2014) provides a good image of the environmental impacts caused by building well-pad infrastructure. The image shows a well-pad, its drilling rig, the tanks and pits required to store water, the supporting generators, and the personnel buildings.

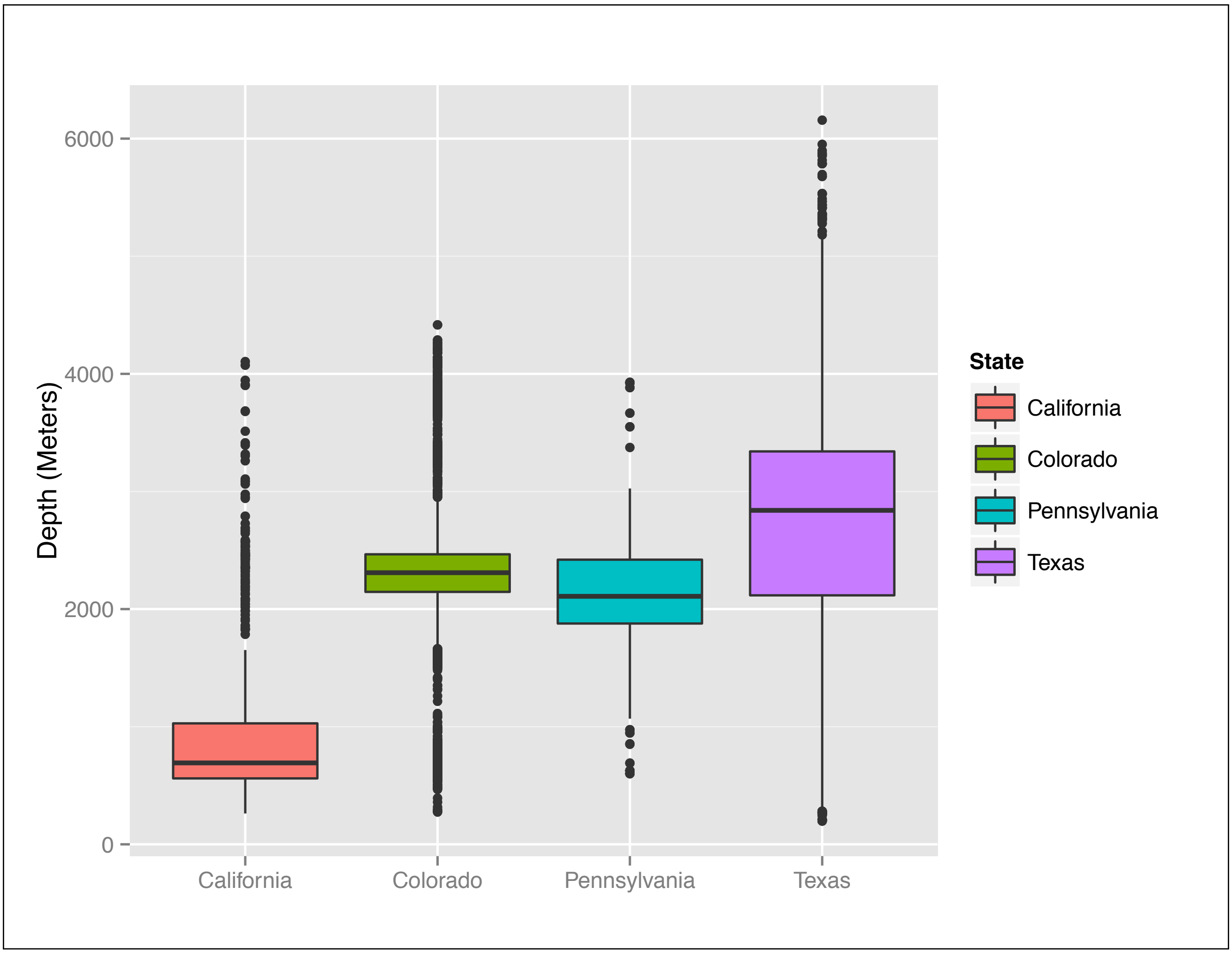
Figure 4: Example Well Site, (EcoFlight 2014)

2.3 Drilling and Cementing

Once the site is prepared, drilling and support equipment are moved into the area and the well is "spudded" (started). This process generates "drill cuttings" which is material removed from the earth from the drilling process and "drill mud" which is usually a fluid of oil and water. Both of these byproducts have to be managed and transported (NYSDEC 2011). The management of these byproducts may require the use of on-site pits, which have their own associated issues that will be discussed further in section 7.2. After spudding, the drill bit is then withdrawn and the well is cemented, the extent of which tapers as the well gets deeper depending on location. During this process, pollution from diesel generators, truck traffic, noise and light disturbance arise.

As shown by figure 5 the vertical depth of the well can vary greatly (anywhere from 200 to 6100 meters) (SkyTruth 2014).[2] The horizontal distance also varies greatly depending on the geological formation (anywhere from 1800 to 3600 meters) (U.S. GAO 2012). Figure 5 shows the variability in depth across states and table 1 gives summary statistics for the entire U.S.

Figure 5: Average Well Depth, (SkyTruth 2014)



[2]This data comes from SkyTruth (2014). *FracFocus Chemical Database Download*. Tech. rep. which is an aggregation of data from FracFocus.org which the national hydraulic fracturing chemical registry. The data is subject to reporting error and so should be seen as indicative of averages and magnitudes rather than exact amounts (Konschnik, Holden, and Shasteen 2013).

Table 1: Summary Statistics for all U.S. Well Depths (meters)

	Minimum	1st Quartile	Median	Mean	3rd Quartile	Max
Well Depth (meters)	198.1	2029	2408	2492	3128	6157

The standards for casings and cementing are established by the American Petroleum Institute (API). This report includes some of the recommended cementing standards in section 7. Each state has its own cement type requirements which are usually flexible to allow for the adjustment of drillers to local conditions (Ground Water Protection Council 2009).

2.4 Hydraulic Fracturing

Once the cement is set, explosives are placed within the horizontal portion of the well and activated at set intervals. These explosions cause the initial fractures in the rock. After this, water has to be prepared at the surface separated in two batches. One batch is an acid mixture used to clear debris and the other is the fracture fluid. Alternative hydraulic fracturing fluids can be used for water-sensitive formations (i.e., formations where permeability is reduced when water is added) or as dictated by production goals (Halliburton, 1988). Examples of alternative fracturing fluids include acid-based fluids; non- aqueous-based fluids; energized fluids, foams or emulsions; viscoelastic surfactant fluids; gels; methanol; and other unconventional fluids (Montgomery 2013).

The most common types of fracturing explosives currently are Octahydro-1,3,5,7-tetranitro-1,3,5,7-tetrazocine (HMX) and 1,3,5-Trinitroperhydro-1,3,5-triazine (RDX) and each charge will contain 3 to 60 grams of explosives. There may be dozens of charges in one hydraulic fracturing job (Hansen 2015; Cosad 1992). It is worth noting that EPA assigned RDX a chronic oral reference dose (RfD) of 3 x 10e-3 milligrams per kilogram per day (mg/kg/day) (EPA IRIS 1993). This agency's risk assessments indicate that the drinking water concentration representing a 1 x 10e-6 cancer risk level for RDX is 0.3 μg/L (EPA IRIS 1993). The Agency for Toxic Substances and Disease Registry (ATSDR) has established a minimal risk level (MRL) of 0.1 mg/kg/day for intermediate-duration oral exposure (15 to 364 days) to RDX (ATSDR 2012).

The acid mixture uses hydrochloric and muriatic acid to clear the pipe of minerals. The amount of acid used varies greatly from well to well depending on geology, with a range of 200-5000 gallons per well. The fracture fluid is used to expand the pre-made fractures and also to deliver proppants to keep the fractures open (Ground Water Protection Council 2009). The fracture solution is brought on-site and mixed with chemicals and sand. The amount of sand used varies from 90,000 kilograms (kg) for a vertical conventional well to 2.5 million kg for horizontal wells (Clark 2011). As for chemicals, the table in section 16 shows a list of some of the chemicals used by the hydraulic fracturing industry and demonstrates their use. The exact volumes and concentrations used vary from well to well and operator to operator.

The solution usually consists of: proppant to keep fractures open to allow hydrocarbons to flow; a breaker chemical which reduces the viscosity of the fluid; significant biocides to prevent the formation of bacteria that could cause sulfurous gases; buffers to adjust the pH of the fluid; a clay stabilizer chemical which prevents the swelling of underground clays; a corrosion inhibitor which prevents rust, a crosslinker chemical which also increases viscosity; additional friction reducers and gelling agents which vary the viscosity; scale inhibitors that prevent build-up on pipes; solvents to break up solids; and surfactants which reduces surface tension (NYSDEC 2011). These tend to make up less than 1% by weight, although the total amount relative to the amount of water gives no indication to the potential harm or toxicity.

This solution is then pumped downhole at extremely high pressure typically ranging from 40,000 to 70,000 kPa, but pressures can be as high as 140,000 kPa (Adams and Rowe 2013). The high pressure expands microscopic cracks and the proppants keep the cracks open after the water flows back with the oil and gas. Once this is completed, the well is flushed with fresh water and oil and gas is allowed to flow (Ground Water Protection Council 2009).

This process is highly dependent on geologic and local conditions for which it may be necessary to adjust the chemical make-up of the fracture fluid as well as the pressures used (Stringfellow et al. 2014). In addition, it is important to note that wells may be re-fractured several times over the lifetime of the well. The purpose is to improve the production performance of the well when production. As the majority of the wells have not reached stripper status, no exact lifetime statistics exist.

2.5 Well Completion and Post-completion

After the well is fractured, the drilling equipment is moved to a different well and the infrastructure required for the collection of oil, gas, and water is installed. During the lifetime of the well, this infrastructure must be maintained and produced water must be treated and disposed of (Clark and Veil 2009). We will explore the impacts of produced water in section 8.1.

Finally, after the productive lifetime of the well, the hole needs to be plugged. This process has to last indefinitely and the surface needs to be restored to its natural state. The purpose of this process is to prevent any future migration of fluids or hydrocarbons into aquifers or surface waters. Every state has its own regulations for the plugging process. Cement, clays, iron plugs, gels, and even drilling mud and water are used to plug the wells at intervals. The specific requirements vary and are outlined again in subsection 7. These plugs need to last forever and usually consist of cement that needs to be set for the subsurface conditions (Ground Water Protection Council 2009). The American Petroleum Institute has specific regulations for plugging.

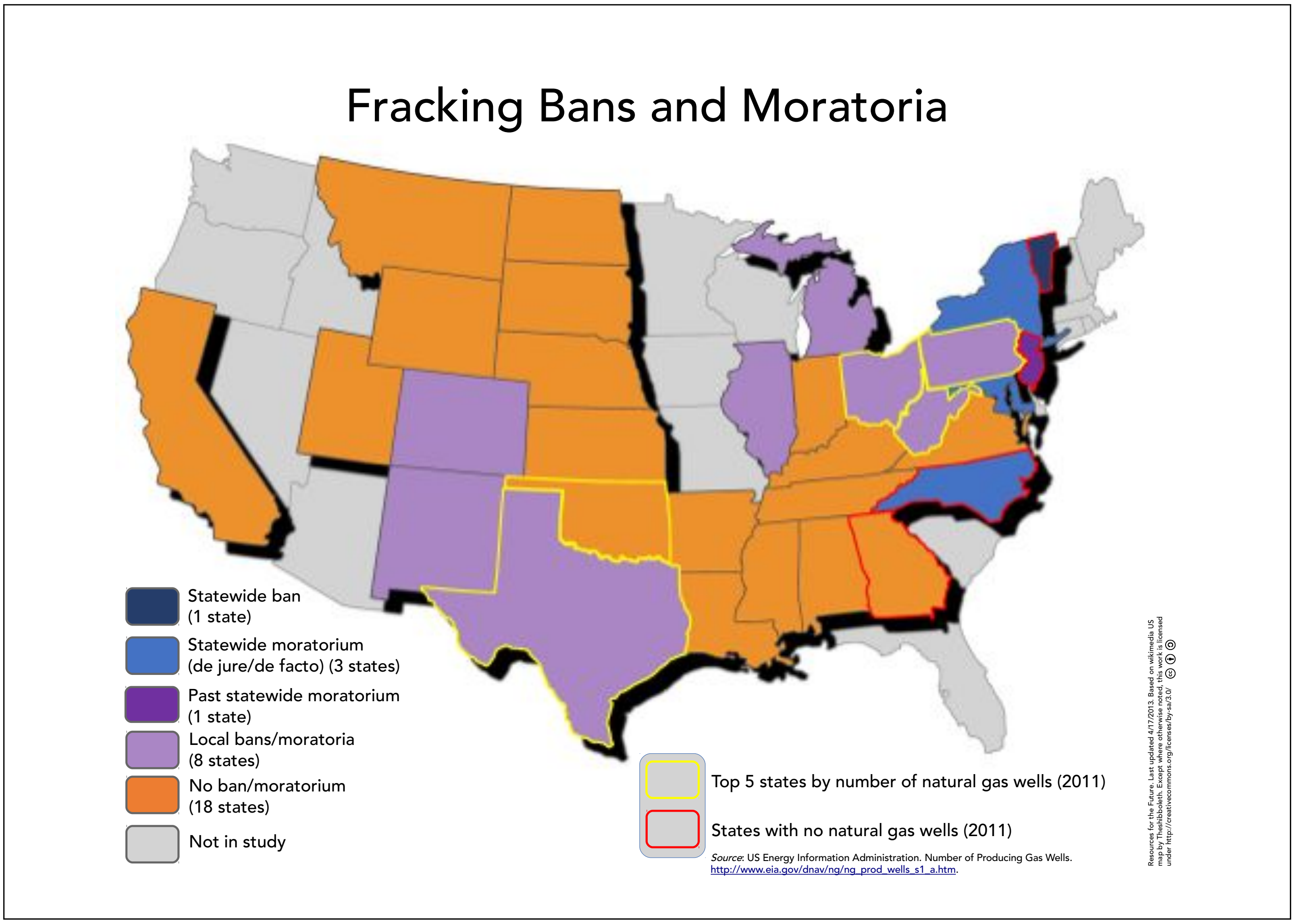
There are more than 2 million plugged and abandoned oil and gas wells in the United States. Some of which have had containment problems, this issue will be explored further in section 7 of this report (Lustgarten 2012).

2.6 Current Issues

The processes associated with hydraulic fracturing have resulted in significant environmental damages and community impacts (Stamford and Azapagic 2014). Reaction has been strong, both on local environmental and health fronts as well as opposition to increased oil and gas supply resulting in lower prices and increased consumption.

The environmental impacts associated with hydraulic fracturing are water contamination, air pollution, ecosystem disruption, spills and releases of toxic materials, greenhouse gas (GHG) emissions, and community quality of life impacts. As such, there have been several regulatory responses to these issues. These are summed up by (Richardson et al. 2013) in figure 6, but should be updated to include that as of January 2015, New York State has banned the practice of hydraulic fracturing. In addition most states require some sort of public disclosure regulations.

Figure 6: (Richardson et al. 2013)



Given the numerous environmental impacts, there have been protests, local bans, statewide bans, and significant opposition from community and environmental groups in reaction to development of hydraulic fracturing projects. We will explore the reasons for this opposition, analyze the impacts using available scientific research, and explore the current regulatory frameworks that have tried to address these issues.

3 Air Impacts

The main air impacts from hydraulic fracturing activities are: emissions of greenhouse gases that contribute to climate change (mainly methane) and volatile organic chemicals that affect air quality. Moreover, there is a feedback effect caused by the high energy requirements of extracting shale oil and gas that results in increased fossil fuel consumption which generates more combustion related emissions and subsequent health hazards of air pollution. This section of the report will analyze these impacts and showcase the current state of information provided by literature and relevant research in this regard.

3.1 Information Sources

(Harvey, Gowrishankar, and Singer 2012)	*The U.S. Oil and Gas Industry Can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste*	"This report focuses on 10 profitable and widely applicable methane emission reduction opportunities in the United States oil and gas (O&G) industry. If these technologies could be used throughout the industry, they have the potential to reduce U.S. methane emissions by more than 80 percent of current levels, based on the U.S. Environmental Protection Agency's (EPA) estimates, an amount greater than the annual greenhouse gas emissions from 50 coal fired power plants. This methane, if captured and sold, can bring in billions of dollars in revenues while benefiting the environment."
(NYSDEC 2011)	*Supplemental Generic Environmental Impact Statement On The Oil, Gas and Solution Mining*	This report is a seminal enivronmental impact statement from New York, it is refered to heavily throughout this report: "During 2008 there was an increased interest in the issuance of permits for horizontal drilling and high-volume hydraulic fracturing to develop the Marcellus Shale and other low-permeability gas reservoirs. The New York Department of Environmental Conservation commenced the development of a Supplemental Generic Environmental Impact Statement (SGEIS) to study its environmental impacts."
(US EPA 2014c)	*Oil and Natural Gas Air Pollution Standards*	This website contains a compendium of information on Oil and Natural Gas Air Pollution Standards
(US EPA 2014b)	*Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012*	The United States Environmental Protection Agency (EPA) prepares the official U.S. Inventory of Greenhouse Gas Emissions and Sinks to comply with existing commitments under the United Nations Framework Convention on Climate Change (UNFCCC). This report is the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012.

(Brandt et al. 2014)	"Energy and environment. Methane leaks from North American natural gas systems."	This study is key to understanding the range of estimates for methane emissions. Some of the conclusions are: "We find (i) measurements at all scales show that offi cial inventories consistently underestimate actual CH4 emissions, with the NG and oil sectors as important contributors; (ii) many independent experiments suggest that a small number of "superemitters" could be responsible for a large fraction of leakage; (iii) recent regional atmospheric studies with very high emissions rates are unlikely to be representative of typical NG system leakage rates; and (iv) assessments using 100-year impact indicators show system-wide leakage is unlikely to be large enough to negate climate benefits of coal-to-NG substitution."
(Miller et al. 2013)	"Anthropogenic emissions of methane in the United States"	"This study quantitatively estimates the spatial distribution of anthropogenic methane sources in the United States by combining comprehensive atmospheric methane observations, extensive spatial datasets, and a high-resolution atmospheric transport model. Results show that current inventories from the US Environmental Protection Agency (EPA) and the Emissions Database for Global Atmospheric Research underestimate methane emissions nationally by a factor of ∼1.5 and ∼1.7, respectively...The spatial patterns of our emission fluxes and observed methane-propane correlations indicate that fossil fuel extraction and refining are major contributors (45 ± 13%) in the south-central United States. This result suggests that regional methane emissions due to fossil fuel extraction and processing could be 4.9 ± 2.6 times larger than in EDGAR, the most comprehensive global methane inventory. These results cast doubt on the US EPA's recent decision to downscale its estimate of national natural gas emissions by 25-30%."
(Allen et al. 2013)	"Measurements of methane emissions at natural gas production sites in the United States"	This is another study on methane emissions and finds estimates to be of the same magnitude as the US EPA's but with greater emissions from equipment leaks. "Overall, if emission factors from this work for completion flowbacks, equipment leaks, and pneumatic pumps and controllers are assumed to be representative of national populations and are used to estimate national emissions, total annual emissions from these source categories are calculated to be 957 Gg of methane (with sampling and measurement uncertainties estimated at ±200 Gg). The estimate for comparable source categories in the EPA national inventory is ∼1,200 Gg."

(Alvarez et al. 2012)	"Greater focus needed on methane leakage from natural gas infrastructure"	This study looks at the larger climate implications of methane leaks from natural gas and stress that end climate scenarios are highly dependent on methane leakage rates. "We find that a shift to compressed natural gas vehicles from gasoline or diesel vehicles leads to greater radiative forcing of the climate for 80 or 280 yr, respectively, before beginning to produce benefits. Compressed natural gas vehicles could produce climate benefits on all time frames if the well-to-wheels CH4 leakage were capped at a level 45-70% below current estimates. By contrast, using natural gas instead of coal for electric power plants can re- duce radiative forcing immediately, and reducing CH4 losses from the production and transportation of natural gas would produce even greater benefits. There is a need for the natural gas industry and science community to help obtain better emissions data and for increased efforts to reduce methane leakage in order to minimize the climate footprint of natural gas."
(Burnham et al. 2012)	"Life-cycle greenhouse gas emissions of shale gas, natural gas, coal, and petroleum."	This study directly compares LCA impacts of hydraulic fracturing. "Our base case results show that shale gas life-cycle emissions are 6% lower than conventional natural gas, 23% lower than gasoline, and 33% lower than coal. However, the range in values for shale and conventional gas overlap, so there is a statistical uncertainty whether shale gas emissions are indeed lower than conventional gas."
(Caulton et al. 2014)	"Toward a better understanding and quantification of methane emissions from shale gas development"	This was an empirical study looking at Pennsylvania and should be noted for its bottom-up methodology as well as identifying that the drilling process is another potentially large source of methane leakage.
(Heath et al. 2014)	"Harmonization of initial estimates of shale gas life cycle greenhouse gas emissions for electric power generation"	This study looks at the life-cycle of electricity with shale gas: " Through a meta-analytical procedure we call harmonization, we develop robust, analytically consistent, and updated comparisons of estimates of life cycle GHG emissions for electricity produced from shale gas, conventionally produced natural gas, and coal. On a per-unit electrical output basis, harmonization reveals that median estimates of GHG emissions from shale gas-generated electricity are similar to those for conventional natural gas, with both approximately half that of the central tendency of coal."

(Jiang et al. 2011)	"Life cycle greenhouse gas emissions of Marcellus shale gas"	"This study estimates the life cycle greenhouse gas (GHG) emissions from the production of Marcellus shale natural gas and compares its emissions with national average US natural gas emissions produced in the year 2008, prior to any significant Marcellus shale development. We estimate that the development and completion of a typical Marcellus shale well results in roughly 5500 t of carbon dioxide equivalent emissions or about1.8 g CO 2 e/MJ of gas produced, assuming conservative estimates of the production lifetime of a typical well. This represents an 11% increase in GHG emissions relative to average domestic gas (excluding combustion) and a 3% increase relative to the life cycle emissions when combustion is included. The life cycle GHG emissions of Marcellus shale natural gas are estimated to be 63-75 g CO 2 e/MJ of gas produced with an average of 68 g CO 2 e/MJ of gas produced."
(US EPA 2011)	*Improving Air Quality in Your Community*	This webiste provides additional information on outdoor air pollution from oil and natural gas production.
(McKenzie et al. 2012)	"Human health risk assessment of air emissions from development of unconventional natural gas resources."	This study "estimated health risks for exposures to air emissions from a NGD project in Garfield County, Colorado with the objective of supporting risk prevention recommendations in a health impact assessment (HIA)." and found that "Residents living $\leq$ .5 mile from wells are at greater risk for health effects from NGD than are residents living $>$ .5 mile from wells. Subchronic exposures to air pollutants during well completion activities present the greatest potential for health effects. The subchronic non-cancer hazard index (HI) of 5 for residents $\leq$ .5 mile from wells was driven primarily by exposure to trimethylbenzenes, xylenes, and aliphatic hydrocarbons. Chronic HIs were 1 and 0.4. for residents $\leq$ .5 mile from wells and $>$ .5 mile from wells, respectively. Cumulative cancer risks were 10 in a million and 6 in a million for residents living $\leq$ .5 mile and $>$ .5 mile from wells, respectively, with benzene as the major contributor to the risk."
(LP Sage Environmental Consulting 2011)	"City of Fort Worth Natural Gas Air Quality Study"	This study commissioned by the Fort Worh City Council addresses the quantity of air pollution, attainment of legal limits, regional air pollution, and setback limits in the Ft. Worth area.
(Bunch et al. 2014)	"Evaluation of impact of shale gas operations in the Barnett Shale region on volatile organic compounds in air and potential human health risks."	This study evaluated VOCs in the Barnett region. "The analyses demonstrate that, for the extensive number of VOCs measured, shale gas production activities have not resulted in community-wide exposures to those VOCs at levels that would pose a health concern."

(Kemball-Cook et al. 2010)	"Ozone impacts of natural gas development in the Haynesville Shale."	This study looks at future potential ozone impacts in the Haynesville shale: "Photochemical modeling of the year 2012 showed increases in 2012 8-h ozone design values of up to 5 ppb within Northeast Texas and Northwest Louisiana resulting from development in the Haynesville Shale. Ozone increases due to Haynesville Shale emissions can affect regions outside Northeast Texas and Northwest Louisiana due to ozone transport. This study evaluates only near-term ozone impacts, but the emission inventory projections indicate that Haynesville emissions may be expected to increase through 2020."
(Olaguer 2012)	"The potential near-source ozone impacts of upstream oil and gas industry emissions."	This study looks at oil and gas development near metropolitan areas and comes to the conclusion that: "Major metropolitan areas in or near shale formations will be hard pressed to demonstrate future attainment of the federal ozone standard, unless significant controls are placed on emissions from increased oil and gas exploration and production."
(Chang et al. 2014)	"Shale-to-well energy use and air pollutant emissions of shale gas production in China"	This study looks at the potenital impacts of shale development in China and finds: "Results suggest shale-to-well energy use of 59 TJ and shale-to-well green- house gas (GHG) emissions of 5500 metric tons of carbon dioxide equivalents (CO2e). Shale-to-well energy use and air emissions were dominated by the production and use of diesel fuel for oil-based drilling fluids and for on-site combustion, and by fugitive emissions and flaring from well completion. The results shed light on some potential energy and air pollutant emission impacts of a shift from coal to shale gas in China, and highlight opportunities for reducing these impacts moving forward."
(Ohio EPA 2014)	*Understanding the Basics of Gas Flaring*	This fact sheet provides basic information about when and why flaring may occur and outlines the regulatory authority over flaring between the Ohio Department of Natural Resources (ODNR), Ohio Environmental Protection Agency (Ohio EPA) and U.S. Environmental Protection Agency (U.S. EPA).
(Leahey, Preston, and Strosher 2001)	"Theoretical and observational assessments of flare efficiencies."	This report models flare stack emissions and finds them dependent on fuel, wind speed, and exit velocity. "Results of theoretical predictions were compared to nine values of local combustion efficiencies obtained as part of an observational study into flaring activity conducted by the Alberta Research Council (ARC)...There was generally good agreement be- ween predicted and observed values. The mean and stan dard deviation of observed combustion efficiencies were 68 ± 7%. Comparable predicted values were 69 ± 7%. "

(US EPA 1991)	*Emission Estimation Protocol for Petroleum Refineries*	This report provides emission factors for flaring and also suggest protocols for assesment.

3.2 Summary of Information

What is clear from the studies is that the exact impacts of air emissions from hydraulic fracturing have not been established. It is likely that large "super-emitters" and VOCs are of primary concern. This is an area of on-going research.

3.3 Analysis of Information

The net impact of GHG emissions from hydraulic fracturing activities is a subject of intense controversy. This debate has focused on two main issues, first: how the massive addition of natural gas for electricity production increases the overall greenhouse gas emissions derived from power generation. Second: whether there is a negative net effect due to methane leakages that outweigh any carbon reduction benefits derived from natural gas replacing more carbon intense fuels for electricity generation. These emissions come from direct releases during venting or from unintended leaks.

According to the Natural Resources Defense Council, 2 to 3 percent of all natural gas produced in the United States is emitted to the atmosphere (NRDC 2012). Venting occurs during normal operation where is used to relieve pressure on valves it also takes place during start-ups and shut-downs. Leaks can also come from defective valves, seals, or errors in operations (New York State Department of Environmental Conservation 2011).

The Obama Administration has recently announced a plan to place limits on methane emissions that stem from the development of oil and gas projects. The content of these regulations are still to be determined, but will most certainly place specific limits on methane emissions from oil and gas (Oil and Natural Gas Air Pollution Standards). On this note, table 3 and 4 provided by (US EPA 2014b) shows the estimates for total annual methane emissions from oil and gas production.

Table 3: US Methane Emissions (Tg CO2 Eq.), (US EPA 2014c)

Activity	1990	2005	2008	2009	2010	2011	2012
Production Field Operations (Potential)	35.3	29.1	29.9	30.1	30.3	31.0	32.2
- Pneumatic device venting	10.3	8.3	8.7	8.8	8.7	9.0	9.1
- Tank venting	5.3	3.9	3.9	4.2	4.4	4.7	5.6
- Combustion & process upsets	2.4	1.9	2.0	2.0	2.0	2.1	2.2
- Misc. venting & fugitives	16.8	14.5	14.8	14.6	14.7	14.7	14.8
- Wellhead fugitives	0.5	0.4	0.5	0.5	0.5	0.5	0.5
- Production Voluntary Reductions	(0.0)	(0.8)	(1.6)	(1.4)	(1.3)	(0.9)	(1.0)
Production Field Operations (Net)	35.3	28.3	28.3	28.7	29.0	30.0	31.2
Crude Oil Transportation	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Refining	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	35.8	28.8	28.8	29.1	29.5	30.5	31.7

Table 4: 2012 EPA Inventory Values, (US EPA 2014b)

Activity	Emission Factor	Unit
Hydraulic Fracturing Completions and Workovers that vent	41	Mg/comp or workover
Flared Hydraulic Fracturing Completions and Workovers	5	Mg/comp or workover
Hydraulic Fracturing Completions and Workovers with reduced emission completions	3	Mg/comp or workover
Hydraulic Fracturing Completions and Workovers with reduced emission completions that flare	6	Mg/comp or workover

As we advance into a carbon-constrained world, the total amount of methane emitted from oil and gas will affect the economic viability of some of these wells. This is, assuming that methane emissions will be included in a carbon price. However, there has been significant controversy regarding the extent of methane emissions due to the fact that the current estimates vary greatly. (Brandt et al. 2014) published a landmark study in which they assumed that many of the inventories and estimates assume rates of leakage much greater than inventories suggest.

The (Brandt et al. 2014) study along with the EPA study can be combined to allow for accurate estimations of methane emissions, however other important analyzes include: (Miller et al. 2013), (Kort et al. 2008), (Katzenstein et al. 2003), (Allen et al. 2013), (Alvarez et al. 2012), (Burnham et al. 2012), (Pétron et al. 2012), (Caulton et al. 2014), (Heath et al. 2014), and (Jiang et al. 2011). All focus on quantifying the methane emissions in the context of global climate change and can be referred to if more regional specifics are needed. The most relevant regulations are EPA's new methane rules due out in the summer of 2015.

Another major issue in relation to air impacts is the health and community impacts of emissions. The emissions of concern are mainly composed of volatile organic compounds (VOCs) which are toxic precursors to ozone. To be more specific they are benzene, toluene, ethylbenzene, xylenes, BTEX, and n-hexane (US EPA 2011a).

To give an idea of the magnitude of concentrations, this report reproduces results from a study done in Garfield County, Colorado by (McKenzie et al. 2012a). The samples were taken every six days from within a natural gas development area. Below is the chart of the average toxic air concentrations produced from oil and natural gas developments:

Table 5: Descriptive statistics for hydrocarbon concentrations, (McKenzie et al. 2012)

Hydrocarbon (μgrams/m3)	Median	SD	95% UCL	Min	Max
1,2,3-Trimethylbenzene	0.11	0.095	0.099	0.022	0.85
1,2,4-Trimethylbenzene	0.18	0.34	0.31	0.063	3.1
1,3,5-Trimethylbenzene	0.12	0.13	0.175	0.024	1.2
1,3-Butadiene	0.11	0.02	0.0465	0.025	0.15
Benzene	0.95	1.3	1.7	0.096	14
Cyclohexane	2.1	8.3	6.2	0.11	105
Ethylbenzene	0.17	0.73	0.415	0.056	8.1
Isopropylbenzene	0.15	0.053	0.074	0.02	0.33
Methylcyclohexane	3.7	4	6.3	0.15	24
m-Xylene/p-Xylene	0.87	1.2	1.3	0.16	9.9
n-Hexane	4	4.2	6.7	0.13	25
n-Nonane	0.44	0.49	0.66	0.064	3.1
n-Pentane	9.1	9.8	14	0.23	62
n-Propylbenzene	0.1	0.068	0.1	0.032	0.71
o-Xylene	0.22	0.33	0.33	0.064	3.6
Propylene	0.34	0.23	0.4	0.11	2.5
Styrene	0.15	0.26	0.13	0.017	3.4
Toluene	1.8	6.2	4.8	0.11	79
Aliphatic hydrocarbons C5-C8	29	NA	44	1.7	220
Aliphatic hydrocarbons C9-C18	1.3	NA	14	0.18	400
Aromatic hydrocarbons C9-C18	0.57	NA	0.695	0.17	5.6

[SD=standard deviation, UCL= Upper Control Limit]

Moreover, a study conducted by (Macey, Breech, and Chernaik 2014) analyzed air quality impacts specific from unconventional oil and gas developments in the states of Wyoming, Arkansas and Pennsylvania and found that Sixteen of the 35 grab samples, and 14 of the 41 passive samples, had concentrations of volatiles that exceeded ATSDR and/or EPA IRIS levels (see table below). The chemicals that most commonly exceeded these levels were hydrogen sulfide, formaldehyde, and benzene. Background levels for these chemicals are 0.15 $\mu g/m^3$ for hydrogen sulfide, 0.25 $\mu g/m^3$ for formaldehyde, and 0.15 $\mu g/m^3$ for benzene. The samples that exceeded health-based risk levels were 90-66,000x background levels for hydrogen sulfide, 30-240x background levels for formaldehyde, and 35-770,000x background levels for benzene.

Table 6: ATSDR minimal risk levels and EPA IRIS cancer risk levels for chemicals of concern (all data in μg/m3), (Macey, Breech, and Chernaik 2014)

Chemical	ATSDR MRLs			Iris Cancer Risk Levels		
	Acute	Intermediate	Chronic	1/1,000,000	1/100,000	1/10,000
Benzene	29	20	10	.45	4.5	45
1,3 butadiene	x	x	x	.03	.3	3
Ethylbenzene	21700	8680	260	x	x	x
Formaldehyde	49	37	10	.08	.8	8
N-hexane	x	x	2115	x	x	x
Hydrogen sulfide	98	28	x	x	x	x
Toluene	3750	x	300	x	x	x
Xylenes	8680	2604	217	x	x	x

It is worth noting that local geologies and weather patterns will affect the concentrations and dispersement of toxic emissions. Therefore, these studies can only give insight into the magnitude. Table 7 shows the results of a study conducted by (LP Sage Environmental Consulting 2011), this study, focuses on point-source emission estimates pertaining to Fort Worth, Texas.

Table 7: Fort Worth Air Quality Report, (LP Sage Environmental Consulting 2011)

Site Type	TOC (tons/yr)		VOC (tons/yr)		HAP (tons/yr)	
	Average	Max	Average	Max	Average	Max
Well Pad	16	445	0.07	8.6	0.02	2
Well Pad with Compressor(s)	68	4433	2	22	0.9	8.8
Compressor Station	99	276	17	43	10	25
Processing Facility	NA	1293	NA	80	NA	47
Saltwater Treatment Facility	NA	1.5	NA	0.65	NA	0.4

TOC= Total Organic Carbon VOC= Volatile Organic Compounds HAP= Hazardous Air Pollutants.

To take a wider view (Bunch et al. 2014) focuses on volatile organic compounds (VOCs) and the environmental and public health consequences this compounds create in the Barnett Shale. This study reached the conclusion that the community-wide impacts were not sufficient to merit a public-health concern. However, they stress the fact that the results may not be extrapolated to other plays.

Conversely, (Kemball-Cook et al. 2010) and (Olaguer 2012) focus on ozone formation and its relation to smog. Their findings suggest that oil and gas developments could increase ozone to above regulatory limits. (Kemball-Cook et al. 2010) find an increase in ozone in the Texas-Louisiana area and (Olaguer 2012) significant ozone increases in the modeled shale gas zones. Ozone has been shown to have significant public health impacts. (Chang et al. 2014) is useful as it provides well-to-wheel emission estimates for various pollutants like NOx and CH4. Even though the content of this study is focused on China. A similar study could be conducted in Mexico.

Hydraulic fracturing activities also have associated air quality impacts derived from heavy traffic that develops due to the transportation requirements of water, materials, and resources. The biggest pollutant from motor vehicle traffic at oil and gas operations is dust, which may cause irritation of the eyes, nose, throat, and skin to people that are overexposed to it. Fracking a single well requires an average of 1,400 truck trips (number provided by Earthworks). Burning fuel to power these trucks emits NOx that reacts with ammonia, moisture, and other compounds to form small particles that penetrate deeply into sensitive parts of the lungs and can cause or worsen respiratory disease, such as emphysema and bronchitis, and can aggravate existing heart disease, leading to increased hospital admissions and premature death; carbon monoxide which causes headaches, dizziness, vomiting, nausea and heart diseases; and sulfur dioxide that causes irritation to the nose and throat, nausea, vomiting, stomach pain and corrosive damage to the airways and lungs.

During certain well operations (mainly completions, maintenance, certain emergency situations) natural gas might be burned in case it cannot be safely, profitably, or practically exploited (Ohio EPA 2014). Flaring practices are usually a consequence of the lack of access to transportation infrastructure. Flaring causes considerable emissions that are the product of wasted resources. The exact scale and composition of emissions from flaring vary with gas type (sour or sweet), wind speed, and flaring equipment (Leahey, Preston, and Strosher 2001). An emission profile of a single flare provided by (US EPA 1991) is shown below as an example:

Table 8: Example Flarestack Emissions, (US EPA 2015)

Component	Emission Factor (kg/TJ)
VOCs	250
Carbon monoxide	130
Nitrogen oxides	1250
Soot	Range of 0 - 274 μg/L

A prime example of a location where flaring is a significant emissions problem is the Bakken play in North Dakota. In general, oil-centered plays will flare lighter hydrocarbons that do not have direct market access infrastructure.

3.4 Conclusions and Regulations

There are considerable air impacts from hydraulic fracturing activities, both in a global-scale through emissions of green house gases that spur climate change; and in a local-scale derived from toxicity issues associated to this developments. This section of the report has focused on analyzing and showcasing the findings of studies while providing relevant data in regards to air impacts. Below the reader will find EPA's guidelines pertaining to National Ambient Air Quality Standards (NAAQS), which address toxic emissions; flaring STRONGER guidelines, and regulations from Ohio (where flaring is banned); and a link to EPA's reconsideration of additional provisions of new source performance standards.

- **Relevant State Regulation - Ohio**

  1509.20 Prevention of waste - gas flaring.

  All owners, lessees, or their agents, drilling for or producing crude oil or natural gas, shall use every reasonable precaution in accordance with the most approved methods of operation to stop and prevent waste of oil or gas, or both. Any well productive of natural gas in quantity sufficient to justify utilization shall be utilized or shut in within ten days after completion.

  The owner of any well producing both oil and gas may burn such gas in flares when it is necessary to protect the health and safety of the public or when the gas is lawfully produced and there is no economic market at the well for the escaping gas.

- **Relevant STRONGER Guideline**

  10.3.2. Source-Specific Requirements
  These guidelines are developed with particular emphasis on VOC and HAP emissions, and control of these pollutants often reduces methane emissions as a co-benefit. However,

there may be some sources that emit dry gas with little or no VOC or HAP content, but that emit methane emissions.. Since 1993, industry partners in the EPA voluntary Natural Gas STAR Program have developed and employed a variety of innovative techniques for mitigating methane emissions in the oil and gas sector. The state should be aware of which operators participate in EPA's Natural Gas STAR program and make others aware of the program. States should be aware of regulatory initiatives of other states to address methane/dry gas emissions.

A state's air quality program should identify oil and gas industry emission source types that must be represented in applications for air quality permits or authorizations. Oil and gas emissions source types and activities may include stationary engines and turbines, well completions or recompletions, venting and leaking gas from compressors, gas-powered pneumatic devices, dehydration units, gas processing plants, transmission and storage facilities, storage vessels and condensate handling, wellbore liquids unloading, produced water management facilities, sweetening units and flares.

The state requirements for these source types and activities should align with Federal requirements unless the state needs to establish additional or more stringent requirements. When specific air issues demand more stringent requirements, states may consider adopting, as consistently as possible, provisions by other states that have been implemented to address similar air quality issue, to minimize the impact on state resources.

State air quality programs may want to address unplanned and episodic emissions due to such things as fugitive air emissions upstream of gas processing plants, process upsets, wellbore liquids unloading, third party equipment downtime, and equipment failure. The programs should require incident reporting and corrective actions where possible, to avoid incident recurrence. However, the state should also consider safety aspects when developing new requirements for unplanned emissions.

Finally, because there is a growing concern over wasted gas from drilling operations, the state air quality regulator should consider coordination with the state oil and gas conservation regulator on a process to quantify and minimize the flaring or venting of associated gas from oil wells.

4 Biodiversity Impacts

In addition to land and air impacts, hydraulic fracturing operations have the potential to severely damage local ecosystems and wildlife, given that normal operations cause noise, air pollution, and habitat clearing.

As each play's ecosystems are slightly different, so to are each play's aggregate impacts. In general these impacts include potential reduction of water, increased pollution of aquatic habitats, noise, clearing to site infrastructure, and traffic disruptions. As noted before, well lifetimes can surpass 20 years and so the biodiversity impacts can be catalogued as multi-generational (New York State Department of Environmental Conservation 2011).

This section of the report will showcase the different biodiversity impacts derived from oil and gas developments, through the analysis of relevant literature and studies pertaining this issue.

4.1 Information Sources

(Gilbert and Chalfoun 2011)	"Energy development affects populations of sagebrush songbirds in Wyoming"	This study looked at songbirds and found: "Results suggest that regional declines of some songbird species, especially sagebrush-obligates, may be exacerbated by increased energy development."
(Sawyer, Kauffman, and Nielson 2009)	"Influence of Well Pad Activity on Winter Habitat Selection Patterns of Mule Deer"	This study looked at mule deer habitat and the effects of oil and gas development. "Model coefficients and predictive maps for both winters suggested that mule deer avoided all types of well pads and selected areas further from well pads with high levels of traffic."
(US EPA 2014d)	*Statoil Eisenbarth Well Response*	This the EPA's response to the Statoil Eisenbarth Well spill in 2014 in Ohio. "Over 16 different chemicals products were staged on the Pad at the time of the explosion and subsequent fire. Materials present on the Pad included but was not limited to: diesel fuel, hydraulic oil, motor oil, hydrochloric acid, cesium-137 sources, hydrotreated light petroleum distillates, terpenes, terpenoids, isoproponal, ethylene glycol, paraffinic solvents, sodium persulfate, tributyl tetradecyl phosphonium chloride and proprietary components. As a result of fire-fighting efforts and flow back from the well head, significant quantities of water and unknown quantities of products on the well pad left the Site and entered an unnamed tributary of Opossum Creek that ultimately discharges to the Ohio River. Runoff left the pad at various locations via sheet flow as well as by two catch basins located at the northwest and southeast corners of the well pad."

(Adams 2011)	"Land application of hydrofracturing fluids damages a deciduous forest stand in West Virginia."	This key study experimentally tested the effects of hydrofracturing fluid on an ecosystem. "In June 2008, 303,000 L of hydrofracturing fluid from a natural gas well were applied to a 0.20-ha area of mixed hardwood forest on the Fernow Experimental Forest, West Virginia. During application, severe damage and mortality of ground vegetation was observed, followed about 10 d later by premature leaf drop by the overstory trees. Two years after fluid application, 56% of the trees within the fluid application area were dead."
(Farag and Harper 2014)	"A review of environmental impacts of salts from produced waters on aquatic resources"	This study looks at the pontential impacts of salts from produced water on aquatic resources, specifically, "A multiple-approach design that combines studies of both individuals and populations, conducted both in the laboratory and the field, was used to study toxic effects of bicarbonate (as NaHCO3)."
(Copeland et al. 2009)	"Mapping oil and gas development potential in the US Intermountain West and estimating impacts to species."	This study models future potential impacts of oil and gas development on various species in the Western United States. Using an example of sage-grouse, the study: " project[s] that future oil and gas development will cause a 7-19 percent decline from 2007 sage-grouse lek population counts and impact 3.7 million ha of sagebrush shrublands and 1.1 million ha of grasslands in the study area."
(Beckmann et al. 2012)	"Human-mediated shifts in animal habitat use: Sequential changes in pronghorn use of a natural gas field in Greater Yellowstone"	Modeling pronghorn ecosystems in the West, this study finds "(1) a five-fold sequential decrease in habitat patches predicted to be of high use and (2) sequential fine-scale abandonment by pronghorn of areas with the greatest habitat loss and greatest industrial footprint. The ability to detect behavioral impacts may be a better sentinel and earlier warning for burgeoning impacts of resource extraction on wildlife populations than studies focused solely on demography."

(Blickley, Blackwood, and Patricelli 2012)	“Experimental evidence for the effects of chronic anthropogenic noise on abundance of Greater Sage-Grouse at leks.”	Looking at sage-grouse, this study finds: "Peak male attendance (i.e., abundance) at leks experimentally treated with noise from natural gas drilling and roads decreased 29% and 73%, respectively, relative to paired controls. Decreases in abundance at leks treated with noise occurred in the first year of the study and continued throughout the experiment. Noise playback did not have a cumulative effect over time on peak male attendance. There was limited evidence for an effect of noise playback on peak female attendance at leks or male attendance the year after the experiment ended. Our results suggest that sage-grouse avoid leks with anthropogenic noise and that intermittent noise has a greater effect on attendance than continuous noise. Our results highlight the threat of anthropogenic noise to population viability for this and other sensitive species."
(Holloran, Kaiser, and Hubert 2010)	“Yearling Greater Sage-Grouse Response to Energy Development in Wyoming”	Another study looking at sage-grouse and energy developments finds: "Yearling males avoided leks near the infrastructure of natural-gas fields when establishing breeding territories; yearling females avoided nesting within 950 m of the infrastructure of natural-gas fields. Additionally, both yearling males and yearling females reared in areas where infrastructure was present had lower annual survival, and yearling males established breeding territories less often, compared to yearlings reared in areas with no infrastructure. Our results supply mechanisms for population-level declines of sage-grouse documented in natural-gas fields, and suggest to land managers that current stipulations on development may not provide management solutions. Managing landscapes so that suitably sized and located regions remain undeveloped may be an effective strategy to sustain greater sage-grouse populations affected by energy developments."
(US Fish and Wildlife Service 2009)	*Reserve Pit Management: Risks to Migratory Birds*	"This document is intended to help U.S. Fish and Wildlife Service (Service) employees and other natural resource managers understand reserve pits, their uses, associated mortality risk to birds and other wildlife, and alternatives to the use of reserve pits in drilling for oil and gas. The information is provided to help Service employees in the review of oil and gas development projects and development of recommendations to prevent or minimize impacts to Service trust resources such as migratory birds, federally-listed threatened and endangered species, and National Wildlife Refuge system lands. The document also provides a summary of state and federal oil and gas rules that relate to reserve pits."

(McEnroe and Sapa 2011)	*Observations and Recommendations to Reduce Fish and Wildlife Impacts from Oil and Gas Development*	Members of the North Dakota Chapter of The Wildlife Society produced a report that includes: "observations and includes recommendations to develop a state comprehensive strategy to avoid, minimize, and mitigate environmental impacts from oil and gas development, provide for more comprehensive review of permit applications, set up research and baseline environmental studies, protect surface owner's rights, provide for more inspectors and stricter enforcement of state regulations, and coordination between state agencies. We believe these recommendations are necessary to conserve and protect the state's natural resources and outdoor heritage."

4.2 Summary of Information

Oil and gas development clearly affects wildlife, the extent of which depends on the local ecosystem. In particular, birds and migratory mammals are impacted greatly. Mitigating these impacts is an area in need of more research.

4.3 Analysis of Information

A number of wildlife studies regarding migratory and plains species in the U.S. states of Colorado and Wyoming have been conducted. These studies focus on the environmental impacts of noise and ecosystem disruption.

A study conducted by (Gilbert and Chalfoun 2011) focuses on songbirds in Wyoming and finds that while some species are unaffected by these development, on a regional scale, there may be evidence for oil and gas developments causing large-scale species decline. (Sawyer, Kauffman, and Nielson 2009) analyze mule deer and found that deer avoided areas of high traffic and well density.

Aquatic life can also be harmed by oil and gas drilling. Not only do net water withdrawals have the potential to reduce the amount of water available for ecosystems, but also spills and other accidents can kill massive amounts of fish and other aquatic life. One such case of a spill in Ohio caused the death of over 70,000 fish in a five-mile stretch of river (US EPA 2014c).

This report addresses plant life in section 4.1 as it equates any land clearing or accidentals spills to a direct impact on plant life, commiserate with the local ecosystem plant life density and sensitivity. The impacts of hydraulic fracturing on plant life are equal to the total land cleared plus any additional impacts from spills and accidents. A study by (Adams 2011) demonstrates that any spills from hydraulic fracturing fluids cause significant mortality in plant species.

As for bird life (Copeland et al. 2009) estimate the impacts of species in the inter-mountain west (Colorado, Utah, Wyoming), the next quote summarizes its findings:

> "Our analysis shows that we can expect a 7-19 percent population decline in sage-grouse from future oil and gas development and that the impacts within our study area will be greatest to sagebrush (3.7 million ha) and grassland (1.1 million ha) ecosystems and the species that inhabit them." -(Copeland et al. 2009)

Similarly (Beckmann et al. 2012) analyzes the impacts of oil and gas developments in Pronghorn (Wyoming) and estimates significant declines in habitat quality. Moreover, (Blickley, Blackwood, and Patricelli 2012) and (Holloran, Kaiser, and Hubert 2010) study the impacts of oil and gas development on sage grouse and find that noise and infrastructure reduced species populations.

Additionally, it has been shown that birds will die if they fly into the pits used by operators to store water. There are prevention measures such as nets, however they may not be sufficient to prevent all deaths (US Fish and Wildlife Service 2009).

4.4 Conclusions and Regulations

This section has analyzed the main biodiversity impacts that stem from oil and gas developments. As it has been mentioned, the exact impacts depend highly on the scale of development and the particularities of the local ecosystems. Baseline data pre and post drilling studies are essential to determine all the potential impacts and liabilities. A study by (McEnroe and Sapa 2011) gives 21 key steps to wildlife management during oil and gas operations. These are listed below.

- Mike McEnroe and Al Sapa (2011). *Observations and Recommendations to Reduce Fish and Wildlife Impacts from Oil and Gas Development*. Tech. rep. URL: `http://joomla.wildlife.org/NorthDakota/images/Documents/oilgas11.pdf`

RECOMMENDATIONS:

As a result of what we saw and learned on the energy tour, there is plenty of evidence and applicable scientific study to show that the state needs a comprehensive strategy to address the impacts from oil and gas development on fish, wildlife, and natural resources. We believe there are many practical adjustments that can be made to activities in the oil patch that are compatible with the industry and that would lessen the impacts to the land and wildlife resources. The development of oil and gas currently underway is clearly having an impact on the state's wildlife and natural resources. The following recommendations address possible legislation, administrative rule making, or agency policies to address the environmental consequences of the current oil boom.

General:

1) First and foremost, the Chapter recommends and requests that the state of North Dakota quickly develop and follow a comprehensive strategic plan for oil and gas development. Such a plan must account for the concurrent development of all the human and social, as well as natural resource infrastructure and development that needs to occur concurrently with oil and gas development and production. The state must see that agricultural and natural resource values are not trampled in the haste to develop an oil and gas resource that is not going anywhere. All the state agencies that deal with energy, agriculture, and social programs that are affected by oil and gas development must be involved in developing and implementing the needed safe guards. This would include the Department of Mineral Resources, State Water Commission, State Agriculture Department, Department of Transportation, Public Service Commission, Game and Fish Department, and possibly other agencies. The U.S. Forest Service has Best Management Practices and the Bureau of Land Management has recommended guidelines for oil development that could serve as starting points for policies or regulations that could be used to protect wildlife and natural resources on state and private lands.

Wildlife and Natural Resources:

2) We recommend that the Department of Mineral Resources and the other involved state and federal agencies strongly enforce existing regulations and implement new regulations, policies, and procedures that conserve the state's wildlife and natural resources by avoiding or minimizing impacts to fish and wildlife, public lands, and natural resources.

3) Where impacts to fish and wildlife, public lands, and natural resources cannot be avoided or minimized then a mitigation process must be developed and implemented to replace or offset the impacts. The oil and gas industry can become impact neutral to the state's other natural resources–fish and wildlife, soil, water, and clean air–with such a process. It is incumbent that fish and wildlife and natural resource professionals develop this process. We believe that a coordinated approach by all affected state agencies, led by the Game and Fish Department, is best suited to lead this process.

Application Process:

4) The State Legislature (2011) passed HB 1241 which requires a seven-day notice to surface owners prior to drilling. The Chapter recommends that advance notice be provided to all surface owners, easement holders, and any third party interests 30 days prior to filing the application for a permit to drill (APD). This would allow more time for the oil company and the surface and/or easement owner to negotiate an agreed upon location for the well site in order to minimize impacts to agricultural operations,

dwelling sites, or sensitive wildlife habitats.

5) We recommend that all APDs be accompanied by maps showing topography and/or wetlands and stream courses or waterways to assist in locating proposed wells and reserve pits away from wetlands and water courses to minimize the impacts of spills and other incidents. With the availability of National Wetland Inventory maps and other GIS spatial data, Natural Resource Conservation Service (USDA) maps, and digital elevation data, this information is not difficult to obtain and use. Many intermittent waterways and temporary and seasonal wetlands are dry in the fall or not detectable under snow cover when well sites are permitted or developed. As a result during spring snowmelt and runoff, they become flooded and create impacts, as well as costly repairs and difficulties for the oil industry. This could be avoided with a minimal amount of planning and permit review. Such review would do much to prevent reserve pit spills during spring runoff events and avoid costly cleanup and remediation actions.

In addition, the Department of Mineral Resources should develop a set of criteria for oil and gas well locations that provide required set-back distances from wetlands, streams, and water courses, slope criteria, and analyses of soil type, and depth to water table. Natural resource data such as species of concern, threatened and endangered species, and special habitat types (sage grouse and sharp-tailed grouse leks, bighorn lambing grounds, or golden eagle nests) should also be noted and considered in the permit process. These criteria and others needed should be developed in coordination with other state agencies and the public.

6) Each ADP must include an emergency and spill response plan. The plan should identify the company personnel in charge of emergency or spill containment procedures, phone numbers or contact information, spill containment procedures, and identify the cleanup materials the company has on hand or available for immediate deployment. The standard for safety should be to have adequate resources in the area (within one hour's deployment time), or contracts with those entities who have resources in the area (within one hour) to be able to respond in an effective timeframe for prevention, mitigation, and cleanup. In addition, the plan shall identify the surface owner, any public land, state or federal agencies who own, administer, or manage land within one mile of or within ten miles downstream of the proposed well site, reserve pit, or oil and gas facility. The plan shall identify the public land agency by name, and list a point of contact and contact information. This information would provide for more immediate response actions in the event of a spill, leak, fire, or other incident.

7) The Oil and Gas Division should develop and follow a system of site specific location criteria to be considered when deciding to permit a well, reserve pit, or oil and gas facility. These criteria shall include distance to a residence, presence of wetlands or stream courses or waterways, historic or cultural resources, unique wildlife habitats or

features.

8) The application process should be opened up in order to allow meaningful testimony from affected surface owners, local forms of government, state and federal agencies, and the public. There must be a voice for public and natural resource interests.

9) A state policy should be developed that designates certain public lands using either a list of to-be-developed criteria, or by specific tract/location as non-surface occupancy areas, i.e., the "primitive" area of the Killdeer Wildlife Management Area, State School Lands. Where public minerals underlie significant blocks of public land currently unauthorized for lease, the minerals should be permanently withdrawn to protect public wildlife and wild land values.

10) We recommend that all APDs that involve hydraulic fracturing (fracking) be required to list the chemicals and ingredients proposed for use in their application. While the oil and gas companies maintain Material Safety Data Sheets (MSDS) at the well site command center, these may not be readily available in an incident such as a fire or explosion. The information should be maintained as a matter of public record on file after the actual period of well drilling. In the event of a leak or later discovered ground water contamination, the list of fracking chemicals could be used to identify the problem well. The list of fracking chemicals may not have to list the quantities or exact recipe for the fracking mixture, but the exact chemicals should be included and maintained by the Department of Mineral Resources.

Reserve pits:

11) We recommend that the Department of Mineral Resources follow through with recent comments that North Dakota should adopt rules prohibiting the use of reserve pits for all future oil and gas developments (Lynn Helms, Bismarck Tribune, May 27, 2011). The state of New Mexico recently approved such legislation (Bismarck Tribune, June 21, 2011). In addition, any new reserve pits, and to the extent possible, all existing pits that are not removed, should be documented with site specific chemical composition and GPS coordinates.

12) We recommend that surface damage payments for siting a well, reserve pit, or other oil and gas facility be based on an appraisal of the devaluation of the entire property and/or the affected property owner's surface rights. Surface damage payments based only on the acreage of the well pad, pit, and accompanying road far under compensate the surface owner for losses. In addition, the oil company should maintain the responsibility and liability for the reserve pit in perpetuity or until the reserve pit is removed from the property.

Transmission and Transportation:

13) We recommend that all pipelines including crude oil, natural gas, and waste disposal and saltwater, should be permitted and regulated by the state of North Dakota, starting at the source and specifically including all gathering lines. The same attention recommended or required for siting above-ground oil and gas infrastructure must be applied to all pipeline corridors and rights-of-way. Pipelines should be sited to exclude blocks of public land managed for wildlife, outdoor recreation, and roadless qualities. Industry coordination should be state sanctioned and regulated to avoid unnecessary cumulative impacts to wildlife, natural resources, and existing agricultural and tourism features, and avoid the unnecessary duplication of facilities.

A concentrated effort should be made to map all existing and abandoned pipelines, making corrections as previously unidentified lines are discovered and future pipelines are developed. We recommend that the state hold jurisdiction for permitting and siting of rail transport facilities for oil and gas transportation, again to coordinate and pace development and avoid redundancy. Similarly, electric transmission lines should be sited to exclude or avoid blocks of public land managed for wildlife, outdoor recreation, or for roadless qualities. All transmission lines and associated structures should be equipped with up-to-date and effective avian and raptor avoidance technology. Again, all transmission lines should be coordinated to avoid or minimize infrastructure disturbance.

Inspections:

14) In spite of recent legislative efforts to provide more Department of Mineral Resources inspectors, the number will still fall short of the number needed to systematically inspect oil and gas wells, drilling sites, and salt water injection wells at currently recommended or required intervals. North Dakota currently has about 176 drilling rigs, and that number is expected to climb to about 225, a 28 percent increase (Bismarck Tribune, May 26, 2011). The inspectors must also continue to monitor and inspect old producing wells and saltwater injection wells at rates and schedules that keep pace with well field development and with current technology. Additional inspectors will help ensure compliance with regulations and prompt response in the event of spills or incidents.

Coordination:

15) We recommend placing a natural resources coordinator on the governor's staff. There are so many aspects to oil and gas development that affect wildlife and natural resources that a natural resource coordinator is needed to facilitate communication and discussion among state agencies, involved federal and local agencies, landowners, and the public on oil and gas, other energy, and natural resource issues. Former North Dakota Governors Link, Olson, and Sinner used such positions on their staff to coordinate the state's interests and identify and facilitate the advocacy for natural resource issues.

16) We recommend a State Coordination Act or consultation process involving the Department of Mineral Resources, State Engineer's Office, State Health Department, Game and Fish Department, Department of Commerce, Department of Tourism,

Parks and Recreation Department, Department of Transportation, and Agriculture Department to plan and accommodate energy development, protect surface owners' rights and property, and conserve natural resources.

17) We recommend and support studies by the wildlife and natural resource agencies and nongovernmental organizations to collect baseline data and objectively evaluate the impacts of oil and gas development and production on wildlife and environmental quality. This includes support for the current Environmental Protection Agency study to evaluate the impacts of hydraulic fracturing processes in North Dakota. We request that wildlife and natural resource agency comments on APDs and all oil and gas developments such as, but not limited to, pipelines, substations, gas plants, and water depots be given due and greater consideration. While we recognize that mineral rights are superior to other property rights, we believe that the mineral and energy resources can and must be developed in a conscientious manner that also protects or minimizes impacts to existing natural resources and community and public values.

18) We recommend establishing a landowner or surface owner hotline or call-in service within the Department of Mineral Resources to get advice or recommendations on how to deal with oil and gas development on their property. The hotline could also serve as an emergency call center for the public to call in a spill or emergency at an oil and gas or energy facility.

Baseline conditions:

19) We recommend that state and federal agencies develop data on current conditions and habitat quality and values, wildlife populations, and public use on public and private lands in order to assess oil and gas and other energy impacts in the future. Such data are necessary in order to make accurate recommendations to avoid and mitigate energy impacts. Such data collection and baseline condition studies will require funding and personnel to accomplish, and we support that funding and personnel requests for both affected state and federal agencies.

20) We recommend that state agencies, especially the Game and Fish Department, be directed to hire additional staff to work on oil and gas issues. At a minimum we recommend a biologist/land manager position and a clerical position for the Williston office, and a biologist/manager for the Dickinson office of the Game and Fish Department.

21) In addition to the sharp-tailed grouse study being conducted by the Game and Fish Department in northwestern North Dakota, we recommend similar studies on big game species, especially mule deer, pronghorn antelope, and white-tailed deer in northwestern North Dakota and the Badlands region, sage grouse in the southwestern portion of the state, and Sprague's pipit in the northwest. The results should be reported to the public

and should include best management practices or criteria to conserve these species.

5 Land Impacts

Oil and gas drilling requires the use of land in every stage of its activity. The quantity and characteristics of the impacts that these portions of land suffer is highly dependent on the particularities of the location of the land given that drilling in a desert causes different long-term impacts than drilling in agricultural or forested areas. This portion of the report will analyze the routine roads and land clearing impacts, the potential spills and accidents, and the long-term concerns that arise from the implementation of hydraulic fracturing activities.

5.1 Information Sources

(NYSDEC 2011)	*Supplemental Generic Environmental Impact Statement On The Oil, Gas and Solution Mining*	This report is a seminal enivronmental impact statement from New York, it is refered to heavily throughout this report: "During 2008 there was an increased interest in the issuance of permits for horizontal drilling and high-volume hydraulic fracturing to develop the Marcellus Shale and other low-permeability gas reservoirs. The New York Department of Environmental Conservation commenced the development of a Supplemental Generic Environmental Impact Statement (SGEIS) to study its environmental impacts."
(BLM 2008)	*Appendix VIII - Hollister Field Office Reasonably Foreseeable Development Scenario for Oil and Gas*	Based on an analysis of past oil and gas related activities within the boundaries of the Hollister Field Office (HFO) and the very small amount of federal mineral estate within areas of high development potential, we project that oil and gas activities on federal mineral estate within the Hollister Field Office area boundary will continue at a relatively minimal level. Overall, within the next 15-20 years, we project total surface disturbance due to all oil and gas activities on federal mineral estate to be no more than 74 acres. This estimate includes geophysical exploration (seismic), 5 exploration wells, 10 development wells and associated facilities, roads, and a transmission pipeline that could be linked to existing transmission lines within the area. One third of this disturbance, 26 acres, will be temporary, and would be mostly to totally reclaimed within a few months to a couple of years. Over the long term, both new and existing oil and gas related activities would eventually be abandoned, the lands would be reclaimed, and the sites would be restored to as near a natural condition as practical.

(The Nature Conservancy 2014)	*Land Use and Ecological Impcats from Shale Development in the Appalachians*	This report is a statement from the Nature Conservancy for the DOE Quadrennial Energy Review public stakeholder Meeting on land use and ecological impacts from shale development in the Appalachians.
(Johnson, Gagnolet, and Ralls 2010)	*Pennsylvania Energy Impacts Assessment*	This report intends to: "Develop credible energy development projections and assess how they might affect high priority conservation areas across Pennsylvania. Marcellus natural gas, wind, wood biomass, and associated electric and gas transmission lines were chosen as the focus since these energy types have the most potential to cause land-use change in the state over the next two decades. The conservation impacts focus is on forest, freshwater, and rare species habitats."
(Evans and Kiesecker 2014)	“Shale gas, wind and water: assessing the potential cumulative impacts of energy development on ecosystem services within the Marcellus play.”	This report looked at future land and ecosystem impacts of energy and finds "Our analysis predicts up to 106,004 new wells and 10,798 new wind turbines resulting up to 535,023 ha of impervious surface (3% of the study area) and upwards of 447,134 ha of impacted forest (2% of the study area). In light of this new energy future, mitigating the impacts of energy development will be one of the major challenges in the coming decades."
(Drohan et al. 2012)	“Early trends in landcover change and forest fragmentation due to shale-gas development in Pennsylvania: a potential outcome for the Northcentral Appalachians.”	This study looks at landcover in Pennsylvania and finds: "Pennsylvania’s shale-gas development is greatest on private land, and is dominated by pads with 1-2 wells; less than 10 % of pads have five wells or more. Approximately 45-62 % of pads occur on agricultural land and 38-54 % in forest land (many in core forest on private land). Development of permits granted as of June 3, 2011, would convert at least 644-1072 ha of agricultural land and 536-894 ha of forest land. Agricultural land conversion suggests that drilling is somewhat competing with food production. Accounting for existing pads and development of all permits would result in at least 649 km of new road, which, along with pipe- lines, would fragment forest cover. The Susquehanna River basin (feeding the Chesapeake Bay), is most developed, with 885 pads (26 % in core forest); permit data suggests the basin will experience continued heavy development. The intensity of core forest disturbance, where many headwater streams occur, suggests that such streams should become a focus of aquatic monitoring. Given the intense development on private lands, we believe a regional strategy is needed to help guide infrastructure develop- ment, so that habitat loss, farmland conversion, and the risk to waterways are better managed.

5.2 Summary of Information

Land impacts span decades with the heaviest impacts during initial development. Spills and other accidents can also have immediate impacts on land and ecosystems. All in all, land use in hydraulic fracturing is significant and needs to be taken into account in planning scenarios.

5.3 Analysis of Information

The first major environmental impact in this regard, is associated with the portion of land required to conduct hydraulic fracturing activities estimated to be at 7.4 acres or roughly 30,000 square meters. This number can vary greatly depending on local conditions, infrastructure requirements, and terrain characteristics. In addition to the impacts on the cleared land, there may be indirect effects on ecosystems near this area due to what is known as the "edge effect" (New York State Department of Environmental Conservation 2011). As ecosystems require a buffer zone, this "edge effect" is the reduction of the buffer zone, which increases overall land impacts. The exact extent of this buffer zone depends on the ecosystem, but can be hundred meters in length.

The cleared land consists of the extension required for the well-pad, the access roads, and the associated infrastructure (compressors, pipelines, electrical lines, and office buildings). The total infrastructure requirements are a function of the quantity of well-pads and their overall development. Thus the total impact is determined by the total number of well-pads in a play.

Table 2 shows different estimates of aggregate land impacts. This is land required directly for oil and gas development (the below estimates do not include the edge effect). In general, these should be taken as estimates into the magnitude and not as exact amounts. (New York State Department of Environmental Conservation 2011). There is no formal method to establishing this buffer zone.

These estimates vary highly as one well pad can contain multiple wells and so should be taken as "per-pad" rather than "per-well". To give an example of the overall magnitude, The Nature Conservancy estimates that 34,000 to 82,000 acres (140 to 330 square kilometers) of forest will be cleared by natural gas developments in Pennsylvania by 2030 (Johnson and Coderre 2011). This land will be in use for decades depending on the lifetime of the wells. (Drohan et al. 2012) analyzes areas in Pennsylvania that have been converted into oil and gas developments and finds that shale oil and gas developments have a significant impact on agricultural and forest lands. It also suggests that trends seen in Pennsylvania have the potential to be seen in other locations. A key finding from the study was that shale gas development had enough of a land impact to compete with food production in the agricultural sector (Drohan et al. 2012).

Apart from land clearing issues, toxic oil, gas and hydraulic fracturing fluids spills can have severe environmental impacts in the body of lands where they occur. The most relevant study regarding spills was conducted by (Adams 2011), this study focused on simulating a spill of hydraulic fracturing fluid upon an experimental forest. The forest experienced significant mortality: "Two years after fluid application, 56% of the trees within the fluid application area were dead." However the author of the study considers that more research regarding these issues is needed. On the other hand, the environmental impacts of oil and gas spills are well documented. The impacts include killing of wildlife, water contamination, and plant and agricultural ecosystems destruction (US EPA 2012b).

To provide context into the total number of spills table 11 gives total number of spills in Colorado. The exact nature of spills including location and quantity will be explored in section 7. While these are not all the spills that occur, they are all the spills that the state regulatory agencies report.

Table 11: Spills in Colorado by Year, (Colorado Oil and Gas Conservation Commission 2014c)

Year	Spills	Oil Spilled (Cubic Meters)	Water Spilled (Cubic Meters)	Oil Produced (Cubic Meters)	Water Produced (Cubic Meters)	Active Wells
2014	544	38	343	1330993	36809038	51737
2013	600	99	360	1640426	61654004	50067
2012	402	114	361	1247862	52732661	46835
2011	499	83	854	995746	54744062	43354
2010	495	83	850	832500	57576167	41010
2009	366	70	561	766933	57124399	37311
2008	408	81	1819	756085	58297044	39944
2007	376	103	685	661480	62475843	33815
2006	336	66	845	619124	63180226	31096
2005	326	127	623	587107	55192363	28952
2004	222	101	938	570521	46984563	26968
2003	213	74	494	545899	48139672	25042
2002	193	81	1462	519980	44962573	23711
2001	206	49	267	510078	42312436	22879
2000	254	90	570	506081	40202470	22228
1999	264	58	1046	498001	36592023	21745

In addition to spills, hydraulic fracturing operations require the management of extremely flammable chemicals and hydrocarbons. As such, the risk of accidental explosions and fires is always present. Although this is not particular of hydraulic fracturing, its scale and speed of development has increased the number of opportunities for accidents.

As for restoration, which is the process of removing equipment and reseeding the area around the well to allow vegetation to grow back. With average well lifetimes extending anywhere between 5-40 years, the timing and process of reclamation is dependent on the particular conditions of the well and the environmental qualities of the area where the well is sited (New York State Department of Environmental Conservation 2011). The long-term recovery potential of these areas is still largely unknown and is highly dependent on management processes. However experience in the conventional sector suggests that full recovery of impacted lands is possible.

5.4 Conclusions and Regulations

Hydraulic fracturing activities cause several land impacts throughout the lifetime of its development. Although there is no scientific consensus regarding the specific quality and quantity of the impacts derived from these developments, enough evidence has been provided to suggest that any regulatory attempt should address land clearing, spills, and long-term restoration implications in order to be successful.

6 Water Impacts

By far the largest area of research regarding hydraulic fracturing has been focused on water. The three largest categories of concern are: the volumetric consumption of water resources, the potential contamination of water supplies, and the management, treatment, and injection of flowback and produced water.[3]

6.1 Total Volumes Used

The total volumetric use of water for hydraulic fracturing has been the center of much local controversy as it has a large impact on communities both in sourcing and transporting the water. Sourcing leads to reductions in availability for other local resources and transporting puts strain on public roads and infrastructure. Additionally, water is an emotional issue and in many hydraulic fracturing plays there is significant scarcity of supply making it a highly visible issue. This report will explore the actual volumes of water used, but it is important to note that water volumes need to be taken in context of where the water is taken from. A gallon of water used in relatively wet Pennsylvania will not have the same issues as a gallon water in dry Texas.

6.1.1 Information Sources

[3]Flowback and produced water are waters that are produced after the drilling a well, this report makes no distinction between the two.

(SkyTruth 2014)	*FracFocus Chemical Database Download*	A database of chemicals that were reported by oil and gas drilling operators as being used in hydraulic fracturing operations. The database contains records for more than 27,000 frack operations from January 2011 through August 2012 in 24 US states. It also includes water volumes.
(Konschnik, Holden, and Shasteen 2013)	"Legal Fractures in Chemical Disclosure Laws: Why the Voluntary Chemical Disclosure Registry FracFocus Fails as a Regulatory Compliance Tool."	This report criticizes FracFocus and finds "The concept of a centralized, on-line registry appeals to under-resourced agencies, since it offers them the ability to delegate data gathering to a third party, and promises transparency by posting some chemical information online. However, our evaluation of FracFocus suggests that reliance on the registry as a regulatory compliance tool is misplaced or premature."
(Freyman and Salmon 2013)	"Hydraulic Fracturing & Water Stress: Growing Competitive Pressures for Water"	"This Ceres research paper analyzes water use in hydraulic fracturing operations across the United States and the extent to which this activity is taking place in water stressed regions. It provides an overview of efforts underway, such as the use of recycled water and non- freshwater resources, to mitigate these impacts and suggests key questions that industry, water managers and investors should be asking."
(Nicot and Scanlon 2012)	"Water use for shale-gas production in Texas, U.S."	As a regional study in Texas, this report can be seen as studying some of the same hydrological conditions as Mexico: "The study objective was to quantify net water use for shale-gas production using data from Texas, which is the dominant producer of shale gas in the U.S. with a focus on three major plays: the Barnett Shale (approx.15 000 wells, mid-2011), Texas-Haynesville Shale (390 wells), and Eagle Ford Shale (1040 wells). Past water use was estimated from well-completion data, and future water use was extrapolated from past water use constrained by shale-gas resources. Cumulative water use in the Barnett totaled 145 Mm3 (2000-mid-2011). Annual water use represents approx.9% of water use in Dallas (population 1.3 million). Water use in younger (2008-mid-2011) plays, although less (6.5 Mm3 Texas- Haynesville, 18 Mm3 Eagle Ford), is increasing rapidly. Water use for shale gas is <1% of statewide water withdrawals; however, local impacts vary with water availability and competing demands."

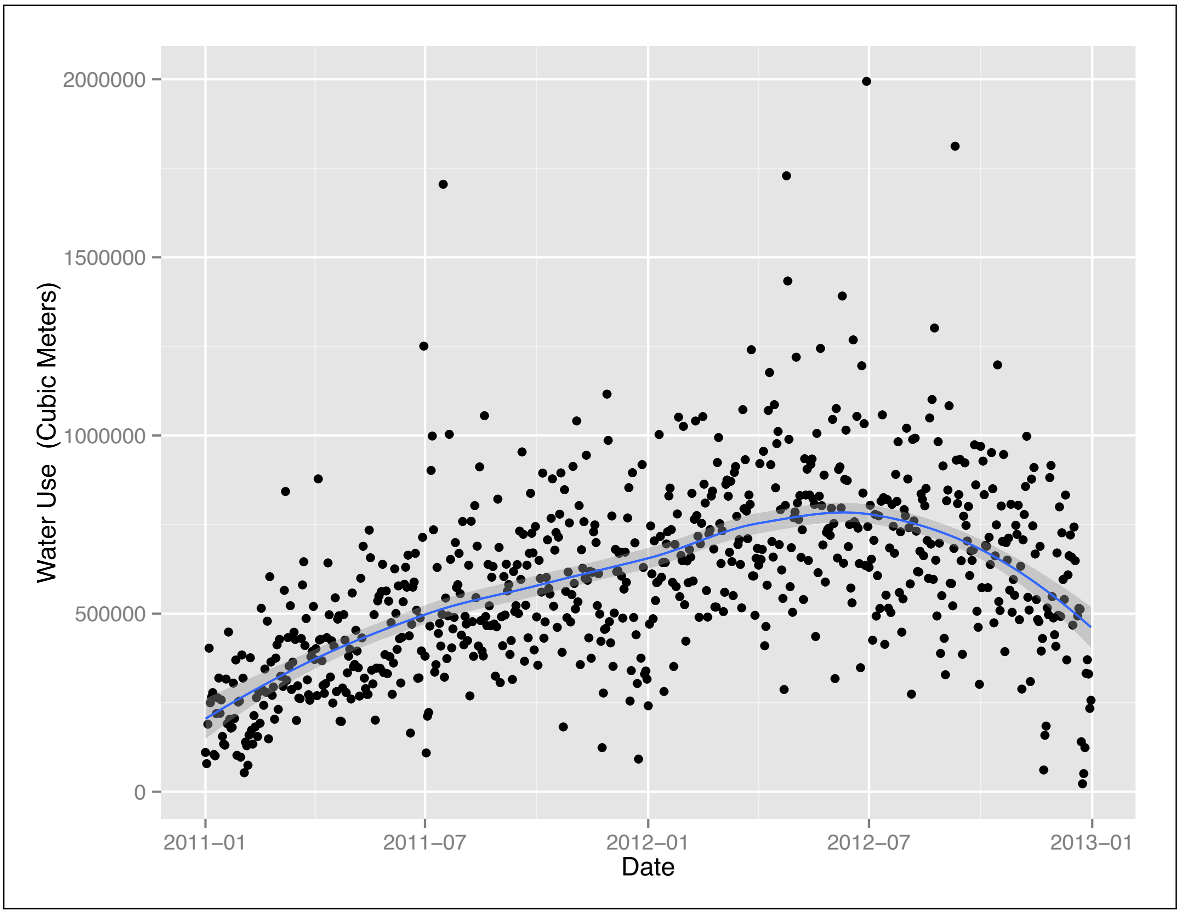
6.1.2 Summary of Information

Most of the water literature draws on data from FracFocus where operators post their water use. From these data, we can get an idea of the average water use by play. However, whether or not this is a burden depends highly on local conditions, as these local conditions vary greatly year-to-year it is hard to predict what actual percentage impact hydraulic fracturing has on local water resources.

6.1.3 Analysis of Information

The total volume of water use for a single well of play depends on the local geology of the shale as well as management practices. Figure 7 is data gathered from FracFocus by (SkyTruth 2014) that looks at total water use in the United States for wells listed on FracFocus. This gives an overall look at the scale of water demands for hydraulic fracturing which in the U.S. ranges from 22,290 to 1,994,000 cubic meters total per day.

Figure 7: Total Daily US Water Use (Cubic Meters), (SkyTruth 2014)

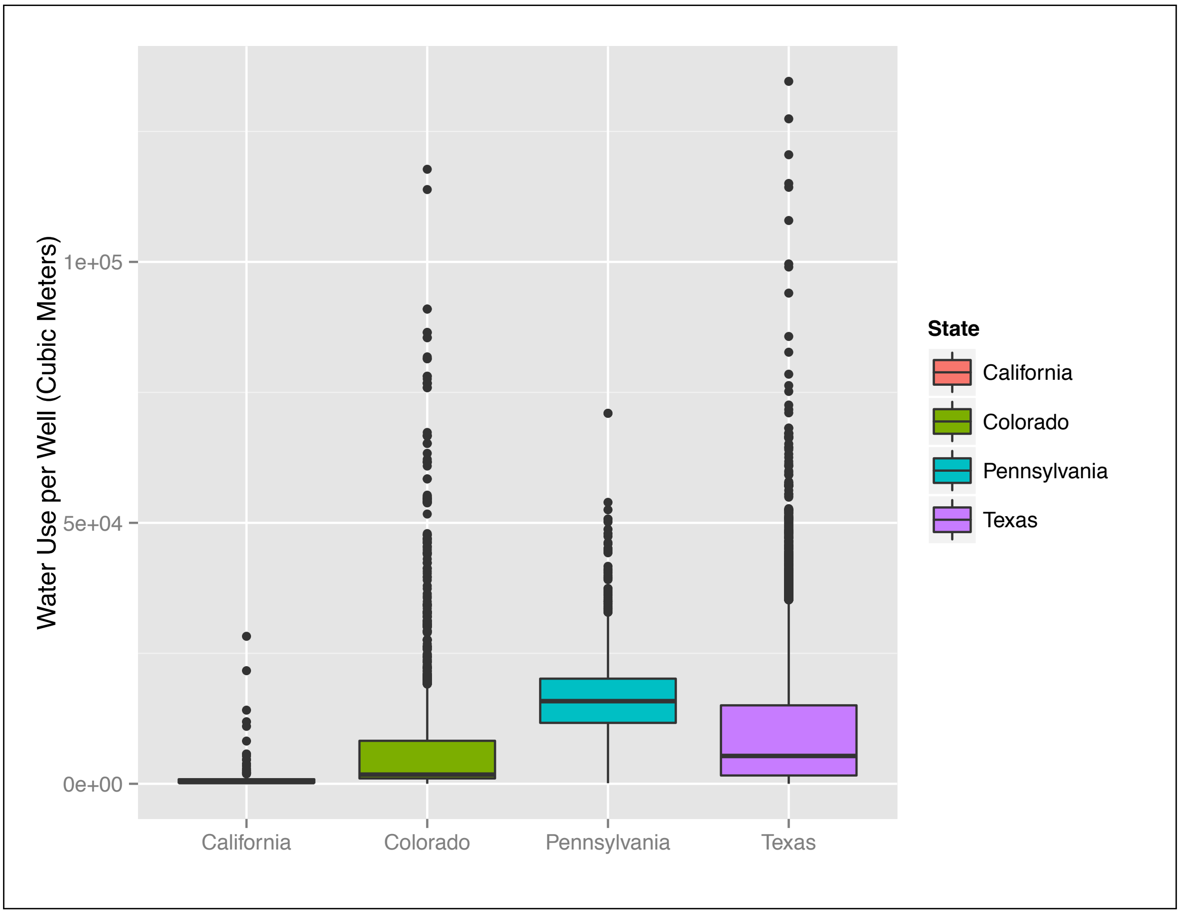


	Minimum	1st Quartile	Median	Mean	3rd Quartile	Max
Total Daily Water Use	22290	409100	584200	591400	747500	1994000

These data do not represent all wells and the accuracy of the underlying data has come under heavy criticism (Konschnik, Holden, and Shasteen 2013). However, it can be used to give insight into the total magnitude of water use in the entirety of the US.

For a more refined picture, figure 8 which was sourced from (SkyTruth 2014) shows the distribution of water use per well by state. The volumes vary greatly per well and per play. This is due to both different operators having separate methods as well as different geologies requiring different volumes of water for hydraulic fracturing.

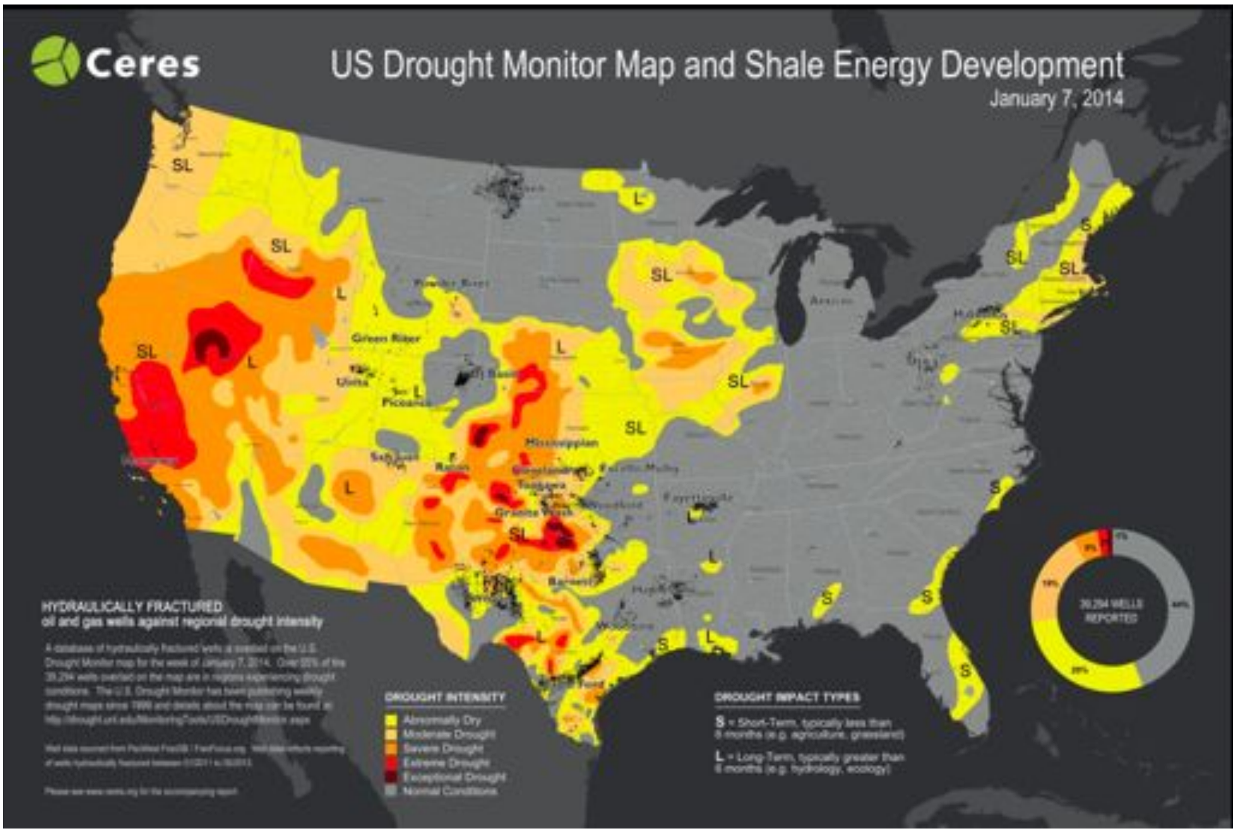
Figure 8: Water Use per Well (Cubic Meters), (SkyTruth 2014)



	Min.	1st Qu.	Median	Mean	3rd Qu.	Max.
Water Use per Well (Cubic Meters)	0.06814	1501	5778	9449	15030	134600

For total and average water use for specific basins (Freyman and Salmon 2013) provides good data in table 13. Figure 9 overlays wells with water stressed regions to give an indication where massive withdrawals could potentially cause resource

Figure 9: Map of Droughts and Shale Plays, (Freyman and Salmon 2013)



conflict.

Table 13: Total Water Use, (Freyman and Salmon 2013), [Converted to M^3]

Water Use Trends (January 1, 2011 - May 31, 2013)	Number of Wells Used to Calculate Water Volume Data	Total Water Use (Cubic Meters)	Average Water Use (Cubic Meters/well)
U.S.	39,294	352 million	9500
DJ Basin (Colorado)	3069	9.5 million	3000
Marcellus (Pennsylvania)	3142	51 million	16,500
Bakken (North Dakota)	2831	23 million	8250
California	848	430,000	500
Permian (Texas)	9308	39 million	4000
Eagle Ford (Texas)	4311	73 million	17,000

In short, hydraulic fracturing requires a significant amount of water over a relatively short 4 to 5 week period. However, looking at total water numbers will not give a picture of the temporal demands of water use. One of the key things to note here is that the majority of water use for hydraulic fracturing is consumptive and thus is unlikely to be returned to the water cycle. We will discuss treatment options for produced water in section 8.4.

For more detailed picture of a specific play in Texas, a study by (Nicot and Scanlon 2012) provides a good summation of the impact. Some conclusions of this study are reproduced in table 14.

Table 14: Water Use in Texas, (Nicot and Scanlon 2012)

Issue	Water Use
Total Water Use in the Barnett Shale Play (2000-2011)	145 Mm3
Annual Water Use	≈9% of water use in Dallas (population 1.3 million)
Total Water use for Shale Gas	$<$1% of statewide water withdrawals

6.1.4 Conclusions

On an aggregate scale, water use for hydraulic fracturing is not insignificant, but the largest impacts are dependent on local conditions. Water source specific analyses are required to asses potential impacts to people and communities.

6.2 Water Sources

The sources of water for hydraulic fracturing are as varied as the geologies of shale plays. They include surface water, ground water, municipal waste water, and water previously used for hydraulic fracturing (US EPA 2012b). The exact percentage division of water source is not clear due to different operator practices, different local water resources, and a lack of data. As a rough estimate, in water-rich Pennsylvania, it is estimated that 72% of the water comes from surface and groundwater and the remaining 28% comes from municipalities, abandoned mines, or rainwater (Penn State Public Broadcasting 2014). This water can be trucked or piped depending on local conditions and then needs to be stored on-site.

6.2.1 Information Sources

(Best and Lowry 2014)	"Quantifying the potential effects of high-volume water extractions on water resources during natural gas development: Marcellus Shale, NY"	This report looks at vulnerable areas of water sourcing as it relates to hydraulic fractuing and finds: "locations in the aquifer and stream networks were identified, which demon- strate particular vulnerability to increased withdrawals and their distribution. These are the locations of importance for planners and regulators who oversee water permitting, to reach a sustainable management of the water resources under changing conditions of energy energy and corresponding water demand."
(Rahm and Riha 2012)	"Toward strategic management of shale gas development: Regional, collective impacts on water resources"	This report looks at regional water resource impacts and comes to the conlusion that: "results indicate that proposed water withdrawal management strategies may not provide greater environmental protection than simpler approaches. We suggest a strategy that maximizes protectiveness while reducing regulatory complexity. For wastewater treatment, we show that the Susquehanna River Basin region of New York State has limited capacity to treat wastewater using extant municipal infrastructure. We suggest that modest private investment in industrial treatment facilities can achieve treatment goals without putting public systems at risk. We conclude that regulation of deterministic water resource impacts of shale gas extraction should be approached on a regional, collective basis, and suggest that water resource management objectives can be met by balancing the need for development with environmental considerations and regulatory constraints."
(Chang, Huang, and Masanet 2014)	"The energy, water, and air pollution implications of tapping China's shale gas reserves"	This study looks at potential development in China on energy, air pollution, and water: "Results suggest that 700-5100 petajoules (PJ) of primary energy will be required for shale gas infrastructure development, while the net primary energy yield of shale gas production over 2013-2020 was estimated at 1650-7150 PJ, suggesting a favorable energy balance. Associated emissions of CO2e were estimated at 80-580 million metric tons, and were primarily attributable to coal-fired electricity generation, fugitive methane, and flaring of methane during shale gas processing and transmission. Direct water consumption was estimated at 20-720 million metric tons. The largest sources of energy use and emissions for infrastructure development were the metals, mining, non-metal mineral products, and power sectors, which should be the focus of energy efficiency initiatives to reduce the impacts of shale gas infrastructure development moving forward. "

6.2.2 Summary of Information

It appears that there is no consensus on water sourcing across the literature, while information on specific cases in Pennsylvania and Texas can be gleaned, the exact source of the water depends greatly on the location, operator, and local water availability.

6.2.3 Analysis of Information

In addition, water rights, distance from wells (transporting is a very expensive), reliability, and water quality (hydraulic fracturing requires relatively clean water to avoid interactions with additives) are all major decision factors in determining water source (NYSDEC 2011). In regards to impacts on local water sources, it all depends on scale. For example, (Best and Lowry 2014) focuses on withdrawal scenarios and municipal groundwater wells and tributary streams to be the most vulnerable impact areas.

For more information, on a larger-scale, (Rahm and Riha 2012) focuses on taking the on strategic regional planning methods and (Chang, Huang, and Masanet 2014) is a general overview on water impacts with a focus on China. If this study could be replicated with relevant local conditions in Mexico it could be of great potential use in policy-making.

6.2.4 Conclusions and Regulations

The existing literature can be used to see total volumes as well as identify potentially vulnerable areas. Overall, the impacts on water from hydraulic fracturing are significant and require regional planning methods to fully address. In regards to relevant regulations, Pennsylvania's Act 220 and API's water management guides are good to refer to.

- **Relevant State Regulation- Pennsylvania:**

  Act 220 and Daily Water Withdrawal/In-stream Flow Requirement Reporting

  The DEP Bureau of Watershed Management requires water systems to report water usage and water withdrawal amounts via monthly/annual reports. DEP provides the capability for the water community to submit the following reports via the web or via paper: Public Water Supply Annual Primary; Facility Report; Non-Public Water Supply Water Withdrawal and Use Primary Facility Report; Sub-Facility Withdrawal and Use Report; and the Daily Water Withdrawal and In-stream Flow Requirement Report.

  The overall business objective is to make the report information available electronically to DEP program staff so that it may be used to monitor the water supplies and usages within Pennsylvania. Paper reports are scanned so that the information is in an electronic format and can be reviewed by DEP staff in the same way as the report information submitted via the web. Once the submitted report information is reviewed and accepted by DEP, the information is loaded into the Department's Water Use Data System (WUDS) and corporate data system known as eFACTS.

http://www.portal.state.pa.us/portal/server.pt/community/egovernment/13826/act_220/588141

- **Relevant API Standard**
  American Petroleum Institute. *API HF2, Water Management Associated with Hydraulic Fracturing, First Edition/June 2010*. URL: http://www.api.org/policy-and-issues/policy-items/hf/api_hf2_water_management.aspx (visited on 01/26/2015)

6.3 Water Quality and Contamination Risks

In addition to impacts on aggregate volumes, one of the main potential vehicles for societal harm from hydraulic fracturing is through water. This is because, as discussed in section 2.4, there are large volumes to be dealt which contain toxic and hazardous materials. The management and disposal of this water from acquisition to disposal requires special focus and should be a top priority in any regulatory scheme. We will discuss what chemicals are mixed with this water, the potential harm from the chemicals, potential contamination pathways, and give examples of proven contamination in the United States.

6.3.1 Information Sources

(Stringfellow et al. 2014)	"Physical, chemical, and biological characteristics of compounds used in hydraulic fracturing."	This study looks at chemicals associated with hydraulic fracturing and finds: "Eighty-one common HF chemical additives were identified and categorized according to their functions. Physical and chemical characteristics of these additives were determined using publicly available chemical informa- tion databases. Fifty-five of the compounds are organic and twenty-seven of these are considered readily or inherently biodegradable. Seventeen chemicals have high theoretical chemical oxygen demand and are used in concentrations that present potential treatment challenges....Gaps in toxicity and other chemical properties suggest deficiencies in the current state of knowledge, highlighting the need for further assessment to understand potential issues associated with HF chemicals in the environment."
(Engle and Rowan 2014)	"Geochemical evolution of produced waters from hydraulic fracturing of the Marcellus Shale, northern Appalachian Basin: A multivariate compositional data analysis approach"	This study looks at the chemical composition of produced waters and finds: "Results from this battery of multivariate tools indicate that two primary processes affect the chemical evolution of the water returned to the surface during the first 90 days of production: mixing of injected water with formation brines of evaporated paleo-seawater origin and injection of sulfate-rich water during hydraulic fracturing may stimulate sulfate reduction at some sites. Spatial variability in sulfate/alkalinity ratios appears to influence variations in geo-chemical controls on strontium versus barium with elevated proportions of strontium being found in more bicarbonate-poor environments, while barium is a larger proportion in sulfate-poor areas."
(Hayes 2009)	"Sampling and analysis of water streams associated with the development of Marcellus shale gas"	This study looks at total dissolved solids in produced waters. It finds chemical constiuents to be similar to those of conventional produced water. It also finds: "Flowback water concentrations of TDS ranged from 680 to 345,000 mg/l; typical profiles show an increase in TDS in flowback water with time following a frac job event."
(Boschee 2014)	*Produced and Flowback Water Recycling and Reuse*	This report reviews the major issues related to produced water and flowback from an industry perspective. It looks at costs, volumes, and treatment technologies.

6.3.2 Summary of Information

From the literature case studies and samples of flowback values can be obtained. However, it also shows that values can vary greatly. Studies also give indication towards the overall toxicity of these constituents of produced water.

6.3.3 Analysis of Information

(Stringfellow et al. 2014) analyzed 81 compounds and found a mix of toxicities, but most alarmingly, could not find toxicity information for 30 of the compounds, this strongly suggests that more research is needed. In regards to chemical constituents, (Engle and Rowan 2014) looks into chemical composition of produced waters. These waters are the end result of the process and while the exact composition may vary, they will include most constituents put into the well except for those that react during the process (e.g. acids and some polymers) (NYSDEC 2011). It will also contain proppants and potentially contain radionuclides that need to be filtered out. The below table from (Hayes 2009) gives an idea of some of the concentrations and constituents within two weeks of hydraulic fracturing of a well in Pennsylvania.

Table 17: Chemical Characteristics of Flowback Water, (Hayes 2009)

Parameter	Range	Median	Units
pH	4.9 - 6.8	6.2	No Units
Acidity	<5 - 473	NC	mg/L
Total Alkalinity	26.1 - 121	85.2	mg/L
Hardness as CaCO3	630 - 95,000	34,000	mg/L
Total Suspended Solids	17 - 1,150	209	mg/L
Turbidity	10.5 - 1,090	233	NTU
Chloride	1,670 - 181,000	78,100	mg/L
Total Dissolved Solids	3,010 - 261,000	120,000	mg/L
Specific Conductance	6,800 710,000	256,000	micromhos/cm
Total Kjeldahl Nitrogen	5.6 - 261	116	mg/L
Ammonia Nitrogen	3.7 - 359	124.5	mg/L
Nitrate-Nitrite	<0.1 - 0.92	NC	mg/L
Nitrite as N	<2.5 - 77.4	NC	mg/L
Nitrate as N	<0.5 - <5	NC	mg/L
Biochemical Oxygen Demand	2.8 - 2070	39.8	mg/L
Chemical Oxygen Demand	228 - 21,900	8530	mg/L
Total Organic Carbon (TOC)	1.2 - 509	38.7	mg/L
Dissolved Organic Carbon	5 - 695	43	mg/L
Oil & Grease (HEM)	<4.6 - 103	NC	mg/L
Cyanide, Total	<10	NC	ug/L
Amenable Cyanide	<0.01	NC	mg/L
Bromide	15.8- 1,600	704	mg/L
Fluoride	<0.05 - <50	NC	mg/L
Total Sulfide	<3.0 - 3.2	NC	mg/L
Sulfite (2)	7.2 - 73.6	13.8	mg/l
Sulfate	<10 - 89.3	NC	mg/L
Total Phosphorus	<0.1 - 2.2	NC	mg/L
Total Recoverable Phenolics	<0.01 - 0.31	NC	mg/L
Sulfite	7.2 - 73.6	13.8	mg/L
Methylene Blue Active Substances (MBAS)	<0.05 - 4.6	NC	mg/L
Samples were collected from 17 locations.			
NC - indicates the median concentration was not calculated due to undetected results.			

Table 18 from (Boschee 2014) shows the range of total dissolved solids (TDS) in certain plays, TDS can be seen as indicator of water quality. This will be explored more in section 8.1.

Table 18: TDS Levels in Various Plays, (Boschee 2014)

Producing Area	TDS (mg/L)
Bakken	150,000 to 300,000
Eagle Ford	15,000 to 55,000
Permian Basin	20,000 to 30,0000
Marcellus	20,000 to 100,000
Denver-Julesburg	20,000 to 65,000

6.3.4 Conclusions

This water is toxic and must be dealt with as a hazardous substance. If it enters an aquifer in sufficient concentrations it can render the aquifer unsafe for use. Given the dependence of many communities on groundwater, the ability of aquifers (or lack there of) to return to a useable state once contaminated, and the unknown harm and long-term fate of many of the chemicals used make underground aquifer contamination one of the worst-case scenarios. Moreover, using surface impoundments to store flow-back water for re-use can derive in leaks that can further cause groundwater and potentially even surface water contamination. Hence, prevention, management, and mitigation should be seen as priorities of any regulatory program.

6.4 Contamination Incidents

In regards to contamination issues, this report will focus on two areas: potential contamination pathways and the risks associated with the chemical constituents of the fracture fluid itself.

6.4.1 Information Sources

(Osborn et al. 2011)	"Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing"	This key study finds evidence for methane contamination in wells. "In aquifers overlying the Marcellus and Utica shale formations of northeastern Pennsylvania and upstate NewYork, we document systematic evidence for methane contamination of drinking water associated with shale- gas extraction."

(Warner et al. 2012)	“Geochemical evidence for possible natural migration of Marcellus Formation brine to shallow aquifers in Pennsylvania”	This study suggests that pathways exist between deep geologic formations and shallow aquifers: "We present geochemical evidence from northeastern Pennsylvania showing that path-ways, unrelated to recent drilling activities, exist in some locations between deep underlying formations and shallow drinking water aquifers....The occurrences of saline water do not correlate with the location of shale-gas wells and are consistent with reported data before rapid shale-gas development in the region; however, the presence of these fluids suggests conductive pathways and specific geostructural and/or hydrodynamic regimes in northeastern Pennsylvania that are at increased risk for contamination of shallow drinking water resources, particularly by fugitive gases, because of natural hydraulic connections to deeper formations."
(Jackson et al. 2013)	“Increased stray gas abundance in a subset of drinking water wells near Marcellus shale gas extraction”	This study links drilling and methane contamination: "Methane was detected in 82% of drinking water samples, with average concentrations six times higher for homes <1 km from natural gas wells (P = 0.0006). Eth- ane was 23 times higher in homes <1 km from gas wells (P = 0.0013); propane was detected in 10 water wells, all within ap- proximately 1 km distance (P = 0.01). Of three factors previously proposed to influence gas concentrations in shallow groundwater (distances to gas wells, valley bottoms, and the Appalachian Structural Front, a proxy for tectonic deformation), distance to gaswells was highly significant for methane concentrations (P =0.007; multiple regression), whereas distances to valley bottoms and the Appalachian Structural Front were not significant (P = 0.27 and P = 0.11, respectively). Distance to gas wells was also the most significant factor for Pearson and Spearman correlation analyses (P<0.01)....Overall, our data suggest that some homeowners living <1 km from gas wells have drinking water contaminated with stray gases."
(Drajem 2013)	*EPA official links fracking and drinking water issues in Dimock, Pa. - The Washington Post*	This article links hydraulic fracturing with water damage in Pennsylvania and states: "Drilling for natural gas caused "significant damage" to drinking-water aquifers in a Pennsylvania town at the center of a fight over the safety of hydraulic fracturing, according to a report prepared by a federal official."
(PA DEP 2014b)	*Water Supply Determination Letters*	These letters are a collection of where the PA DEP has determined that oil and gas activities have impacted water supplies.

(Mall 2011)	*Incidents where hydraulic fracturing is a suspected cause of drinking water contamination | Amy Mall's Blog | Switchboard, from NRDC*	These are a collection of suspected oil and gas impacts gathered by Amy Mall of the NRDC on her blog.
(Vidic et al. 2013)	"Impact of shale gas development on regional water quality."	This report: "review[s] the current understanding of environmental issues associated with unconventional gas extraction. Improved understanding of the fate and transport of contaminants of concern and increased long-term monitoring and data dissemination will help manage these water-quality risks today and in the future."

6.4.2 Summary of Information

These studies strongly suggest that water contamination is associated with hydraulic fracturing this given the risks that this activity poses in terms of accidents and spillages that result from tank ruptures, equipment failures, impoundment overflows, operation errors, inadequate storage, rainfall, run-off, and cement casing issues. It also includes non-academic, non-proven case studies.

6.4.3 Analysis of Information

According to Vidic et al. 2013 The most common contamination seen is through increase methane in aquifers. (Osborn et al. 2011) found that methane levels in drinking water wells within active development zones were elevated to hazardous levels compared to wells outside of the extraction area.

A study by (Warner et al. 2012) predicts that methane contamination will be the most likely evidence of hydraulic connections. Indeed, the most common incidents of contamination seem to be of gases. A study by (Jackson et al. 2013) also proves methane contamination in drinking water wells near drilling activity. Notorious public incidents include in Pavilion, Wyoming where chemicals from hydraulic fracturing were found in a drinking water aquifer. The U.S. EPA has directly linked well contamination to oil and gas drilling activities in Dimock, Pennsylvania (Drajem 2013).

The Natural Resources Defense Council has aggregated incidents of suspected water contamination. While legal proof has not been established in most of the following cases, we included them to highlight potential incidents and illustrate some complaints. Whether these incidents are caused by hydraulic fracturing, the industrial process of drilling and production itself, or completely independent of oil and gas development most likely will never be known completely due to the lack of baseline data among other reasons (see section 12.5 for more information on baseline data). However, we thought we would include them to give an idea of some of the complaints, proven or unproven, that are associated with oil and gas development.

Arkansas: In 2008, Charlene Parish of Bee Branch reported contamination of drinking water during hydraulic fracturing of a nearby natural gas well owned by Southwestern Energy Company. Her water smelled bad, turned yellow, and filled with silt.

Arkansas: In 2007, the Graetz family in Pangburn reported contamination of drinking water during hydraulic fracturing of a nearby natural gas well owned by Southwestern Energy Company. The water turned muddy and contained particles that were "very light and kind of slick" and resembled pieces of leather.

Arkansas: In 2009, a family in Bee Branch, who wishes to remain anonymous, reported changes in water pressure and drinking water that turned gray and cloudy and had noxious odors after hydraulic fracturing of a nearby natural gas well owned by Southwestern Energy Company.

Arkansas: In 2007, a family in Center Ridge reported changes in water pressure and water that turned red or orange and looked like it had clay in it after hydraulic fracturing of nearby wells owned by Southwestern Energy Company. They told their story on YouTube.

Arkansas: In 2008, a homeowner in Center Ridge reported changes in water pressure and water that turned brown, smelled bad, and had sediment in it after hydraulic fracturing of a nearby well owned by Southwestern Energy Company. He also told his story on YouTube.

Colorado: In 2001, two families in Silt reported a water well blow-out and contamination of their drinking water during hydraulic fracturing of four nearby natural gas wells owned by Ballard Petroleum, now Encana Corporation. Their drinking water turned gray, had strong smells, bubbled, and lost pressure. One family reported health symptoms they believe are linked to the groundwater contamination.

Colorado: In 2007, the Bounds family in Huerfano County reported a pump house exploded and contamination of drinking water during hydraulic fracturing of nearby wells owned by Petroglyph Energy.

Colorado: In June, 2010, the day hydraulic fracturing began on a nearby gas well in Las Animas County, landowner Tracy Dahl checked his cistern and found approximately 500 gallons of grayish brown murky water where water had previously run clear for years. The Dahls have extensive water testing documentation going back many years, verifying that their water has always been clean and clear. They were told by Colorado Oil and Gas Conservation Commission ("COGCC") staff that the water could not be tested for chemicals in the hydraulic fracturing fluid because there is insufficient information about the chemicals used. Three monitor wells on the ranch are now producing methane at an escalating rate.

Michigan: In June, 2013, Bernard and Phyllis Senske, who live adjacent to a fracking site in Rapid River

Township, reported that they started experiencing a drop in water pressure and discolored water. An independent investigation found that found that "the static water level within the Senske well has been lowered by 11 feet." According to Mrs. Senske: "It looks like milk coming out of the faucet." According to EcoWatch, the Senskes report that no problems have existed with water quality or quantity in this water well, which installed approximately in the early 1990s, and the only obvious change in the vicinity is the nearby horizontal fracking operation.

New Mexico: A 2004 investigation by the U.S. Environmental Protection Agency found two residents who reported that the quality of their water was affected by hydraulic fracturing.

New York: In 2007, the Lytle family in Seneca County reported contamination of drinking water the morning after hydraulic fracturing of a nearby natural gas well owned by Chesapeake Energy Corporation. The water turned gray and was full of sediment.

New York: In 2009, the Eddy family in Allegany County reported contamination of drinking water during hydraulic fracturing of a nearby well owned by U.S. Energy Development Corporation. The water turned "foamy, chocolate-brown."

North Dakota: The North Dakota non-profit organization Bakken Watch reports very serious health symptoms in humans, livestock, and pets after nearby hydraulic fracturing. Their website has photos of sick animals, pit leaks, and corroded tanks. North Dakota state legislators admit they are "understaffed and overwhelmed" and "struggling to provide adequate oversight amid an explosion of activity in North Dakota's oil patch."

Ohio: In 2007, there was an explosion of a water well and contamination of at least 22 other drinking water wells in Bainbridge Township after hydraulic fracturing of a nearby natural gas well owned by Ohio Valley Energy Systems. According to the State investigation, one of the contributing factors to this incident is that: "the frac communicated directly with the well bore and was not confined within the "Clinton" reservoir."

Pennsylvania: Michael and Nancy Leighton of Granville Summit, Pennsylvania, report that tests of their drinking water found clean and safe water in May, 2011, before fracking occurred near their home, but that water testing conducted in May, 2012–after nearby fracking–found substantial increases in the levels of methane, ethane, propane, iron and manganese in their groundwater. They report that their water "drastically changed in clarity and color, had a foul odor, contained noticeable levels of natural gas," and had "become flammable." In addition, they report that the creek on their property began bubbling at the surface.

Pennsylvania: In May, 2011, fracking began near the home of Jim Harkins in Allegheny Township in Potter County. Jim reported that his water turned brown two days later. Jim says he is a life-long Republican who is not against drilling, but thinks there should be "safe, responsible development of our natural resources."

Pennsylvania: A gas well near the home of the Simons family in Bradford County was drilled in 2009 and re-fracked in February, 2011. Shortly after the 2011 operation, the Simons family reports that their tap water turned gray and hazy. After the water changed, family members began getting severe rashes with oozing blisters, and one child had to be taken to the hospital for torrential nosebleeds that would not stop, nausea and severe headaches. The Pennsylvania Department of Environmental Protection (DEP) tested the water and found very high levels of methane and other contaminants in the water, but said it was safe to drink. Since the Simons family stopped using any of their water, these symptoms have gone away but the water still "stinks awfully; it is a scummy, rotten, nasty smell..."

Pennsylvania: In September, 2010, a lawsuit was filed by 13 families who say they have been and continue to be exposed to contaminated drinking water linked to hydraulic fracturing. Eight different properties in Susquehanna County are said to have contaminated drinking water. One child has neurological symptoms consistent with exposure to toxic substances. Southwestern Energy, the company operating the well near these families, responded that it promptly investigated all complaints and that both the company and the Pennsylvania Department of the Environment independently tested the water and found no link between gas operations and the water quality and no problems with the integrity of the gas well.

Pennsylvania: In 2009, the Zimmerman family of Washington County reported contamination of drinking water after hydraulic fracturing of nearby natural gas wells owned by Atlas Energy. Water testing on their farm found arsenic at 2,600 times acceptable levels, benzene at 44 times above limits, naphthalene at five times the federal standard, and mercury and selenium levels above official limits.

Pennsylvania: In 2008, two families in Gibbs Hill reported contamination of drinking water after hydraulic fracturing of a nearby natural gas well owned by Seneca Resources Corporation. Their water had strong fumes, caused burning in lungs and sinuses after showering, and caused burning in the mouth immediately upon drinking. The state found that the company had not managed the pressure in the well properly and had spilled used hydraulic fracturing fluids that contaminated the drinking water supply.

Pennsylvania: In 2009, families in Bradford Township reported contamination of drinking water after hydraulic fracturing of nearby natural gas wells owned by Schreiner Oil & Gas. The drinking water of at least seven families has been contaminated.

Pennyslvania: In 2009, the Smitsky family in Hickory reported contamination of their drinking water after hydraulic fracturing of nearby natural gas wells owned by Range Resources. Their water became cloudy and foul-smelling. Testing found acrylonitrile, a chemical that may be used in hydraulic fracturing.

Pennsylvania: A family in Bradford County reports that its water turned black and became flammable from methane contamination in 2009 after hydraulic fracturing of a nearby well operated by Chesapeake Energy. The water cleared for a while but turned black again in 2010. Relatives living down the road also report their water turning black in 2010.

Texas: Larry Bisidas is an expert in drilling wells and in groundwater. He is the owner of Bisidas

Water Well Drilling in Wise County, and has been drilling water wells for 40 years. Two water wells on his property became contaminated in 2010. When his state regulator stated that there has been no groundwater contamination in Texas related to hydraulic fracturing, Mr. Bisidas replied: ""All they've gotta do is come out to my place, and I'll prove it to them."

Texas: In Wise County, Catherine and Brett Bledsoe report that their drinking water became contaminated in 2010 soon after hydraulic fracturing began on two natural gas wells bordering their property. The water stung their eyes during showers, and their animals refused to drink the water. Without any assistance from regulators, the Bledsoes paid for their own water testing. The testing found benzene, a known carcinogen, at double the safe levels.

Texas: In 2007, three families who share an aquifer in Grandview reported contamination of drinking water after hydraulic fracturing of a nearby well owned by Williams. They experienced strong odors in their water, changes in water pressure, skin irritation, and dead livestock. Water testing found toluene and other contaminants.

Texas: The Scoma family in Johnson County is suing Chesapeake Energy, claiming the company contaminated their drinking water with benzene and petroleum by-products after hydraulic fracturing of natural gas wells near the Scoma home. The family reports that its drinking water sometimes runs an orange-yellow color, tastes bad and gives off a foul odor.

Texas: Tarrant County Commissioner J.D. Johnson, who lives in the Barnett shale area, reported groundwater contamination immediately after two gas wells on his property were hydraulically fractured. His water turned a dark gold color and had sand in it.

Texas: Carol Grosser, in south Texas, noticed changes in her water after a neighbor told her a nearby well was being hydraulically fractured. Carol noticed changes in her water pressure and rust-colored residue in her stock tanks. The fish in her tanks died, and some of her goats had abnormal milk production and produced kids with unusual birth defects.

Texas: Toby Frederick began noticing a foul odor and discoloration in his water after "an oil company blew out some casing during a hydraulic fracturing job northeast of his property." Mr. Frederick paid for his own water samples, which found traces of benzene, a known carcinogen, in his water. He sent samples to his local Ground Water Conservation District, but never received any results. The Texas Railroad Commission told him his water was drinkable, even though it is brown and smells like diesel fuel.

Texas: The Executive Director of the Upper Trinity River Groundwater Conservation District in north Texas stated that the District "gets 'regular reports' from property owners who said that 'since a particular [gas] well had been fracked, they've had problems' with their water wells, such as sand in them, saltier water or reduced water output...."

Texas: Susan Knoll in the Barnett shale reports that last year her drinking water became foamy right after hydraulic fracturing of a well adjacent to her property. Since that time, additional gas wells have been fractured near her home and her drinking water has continually gotten worse. It sometimes foams, becomes oily, and has strong odors that burn Susan's nose when she smells her water. Susan has a lot of videos and more information on her blog.

Texas: Grace Mitchell, a resident of Johnson County, Texas, is suing Encana and Chesapeake. According to her lawsuit, soon after drilling and hydraulic fracturing took place near her home in 2010, her water became contaminated, feeling slick to the touch and giving off an oily, gasoline-like odor. Testing results performed on her well water confirmed it was contaminated with various chemicals, including C-12-C28 hydrocarbons, similar to diesel fuel.

Texas: The Harris family of Denton County, Texas, is suing Devon Energy. They say that their water became contaminated soon after Devon commenced drilling and hydraulic fracturing near their home in 2008, and that their water became polluted with a gray sediment. Testing results performed on the well water found contamination with high levels of metals: aluminum, arsenic, barium, beryllium, calcium, chromium, cobalt, copper, iron, lead, lithium, magnesium, manganese, nickel, potassium, sodium, strontium, titanium, vanadium, and zinc.

Virginia: Citizens reported drinking water contamination after hydraulic fracturing. Water was murky and had oily films, black sediments, methane, and diesel odors. Individuals experienced rashes from showering. The Buchanan Citizens Action Group reported over 100 documented complaints of adverse effects of hydraulic fracturing and the Dickenson County Citizens Committee reported ground water quality deteriorated throughout the county as a result of the large number of hydraulic fracturing events.

West Virginia: The Hagy family in Jackson County, West Virginia, is suing four oil and gas companies for contaminating their drinking water. They say their water had "a peculiar smell and taste" and the parents as well as their two children are suffering from neurological symptoms. A news article reports that the lawsuit makes the connection between the drinking water contamination and the hydraulic fracturing process.

West Virginia: In Marshall County, Jeremiah Magers reported in October, 2010, that "As soon as they 'fracked' those gas wells, that's when my water well started getting gas in it." He also lost all the water in his well.

West Virginia: In Wetzel County, Marilyn Hunt reported to the EPA in 2010 that: "frac drilling is contaminating the drinking water here." Residents report health symptoms, such as rashes and mouth sores, as well as illness in their lambs and goats, which they suspect is linked to drinking water contamination.

Wyoming: Families in the small town of Pavillion have been reporting contamination of their drinking water for at least ten years. Hydraulic fracturing has been used in the many wells in the area owned by Encana Corporation. Drinking water has turned black, smelled bad, and tasted bad. Individuals report medical symptoms they believe are related to water contamination. The U.S. Environmental Protection Agency found contamination in 11 water wells, and concluded in the draft report on its investigation that: "the data indicates likely impact to ground water that can be explained by hydraulic fracturing."

Amy Mall (2011). *Incidents where hydraulic fracturing is a suspected cause of drinking water contamination | Amy Mall's Blog | Switchboard, from NRDC*. tech. rep. URL: `http : / / switchboard . nrdc . org / blogs / amall / incidents \ _where \ _hydraulic \ _frac . html` `http://switchboard.nrdc.org/blogs/amall/incidents_where_hydraulic_frac.html`

In contrast to the above, legally proven impacts are demonstrated by the PA DEP's "Water Supply Determination Letters" where it the DEP has determined that oil and gas activities (not necessarily hydraulic fracturing) have impacted private water supplies. As of December 2014, 250 letters had been issued (PA DEP 2014b).

6.4.4 Conclusions

Based on the information from (PA DEP 2014b) and the work by (Vidic et al. 2013) it is clear that hydraulic fracturing activity can cause contamination of water resources. The exact method of contamination is often hard to prove, but several scientific studies help point to likely causes. We separate these into subsurface and surface pathways.

6.5 Subsurface Contamination Pathways

One of the main concerns with hydraulic fracturing are unseen connections between deep shales and shallow aquifers.

6.5.1 Information Sources

(Rozell and Reaven 2012)	"Water pollution risk associated with natural gas extraction from the Marcellus Shale."	This study identifies risk pathways, namely: "the study model identified five pathways of water contamination: transportation spills, well casing leaks, leaks through fractured rock, drilling site discharge, and wastewater disposal. Probability boxes were generated for each pathway. The potential contamination risk and epistemic uncertainty associated with hydraulic fracturing wastewater disposal was several orders of magnitude larger than the other pathways."
(Kharak et al. 2013)	"The Energy-Water Nexus: Potential Groundwater-Quality Degradation Associated with Production of Shale Gas"	This study analyzies flowback waters and in particular looks at NORM. It finds : "results show that flow back and produced waters from Haynesville (Texas) and Marcellus (Pennsylvania) Shale have high salinities (greater than/equal to 200,000 mg/L TDS) and high NORMs (up to 10,000 picocuries/L) concentrations."

(Darrah et al. 2014)	"Noble gases identify the mechanisms of fugitive gas contamination in drinking-water wells overlying the Marcellus and Barnett Shales"	"Hydrocarbon production from unconventional sources is growing rapidly, accompanied by concerns about drinking-water contamination and other environmental risks. Using noble gas and hydrocarbon tracers, we distinguish natural sources of methane from anthropogenic contamination and evaluate the mechanisms that cause elevated hydrocarbon concentrations in drinking water near natural-gas wells. We document fugitive gases in eight clusters of domestic water wells overlying the Marcellus and Barnett Shales, including declining water quality through time over the Barnett. Gas geochemistry data implicate leaks through annulus cement (four cases), production casings (three cases), and underground well failure (one case) rather than gas migration induced by hydraulic fracturing deep un- derground. Determining the mechanisms of contamination will improve the safety and economics of shale-gas extraction."
(Myers 2012)	*Potential contaminant pathways from hydraulically fractured shale to aquifers.*	This study finds that underground water transport can be significantly affected by shale development: "Interpretative modeling shows that advective transport could require up to tens of thousands of years to move contaminants to the surface, but also that fracking the shale could reduce that transport time to tens or hundreds of years. Conductive faults or fracture zones, as found throughout the Marcellus shale region, could reduce the travel time further. Injection of up to 15,000,000 L of fluid into the shale generates high pressure at the well, which decreases with distance from the well and with time after injection as the fluid advects through the shale. The advection displaces native fluids, mostly brine, and fractures the bulk media widening existing fractures. Simulated pressure returns to pre-injection levels in about 300 d. The overall system requires from 3 to 6 years to reach a new equilibrium reflecting the significant changes caused by fracking the shale, which could allow advective transport to aquifers in less than 10 years."
(Capo et al. 2014)	"The strontium isotopic evolution of Marcellus Formation produced waters, southwestern Pennsylvania"	This study looks at the strontium isotope development of produced waters and finds "Taken together with results from earlierwork, these data suggestmixing between injected frac fluid and high-TDS formationwater, highly enriched in Sr, and isotopically relatively uniform throughout theMarcellus shale gas play. This brine could existwithin porous lenses of organicmatter in the shale, in pre-existing fractureswithin the shale, and/or originate fromfluids that migrated fromadjacent formations at some point during the post-depositional history of the basin."

(Barbot et al. 2013)	“Spatial and temporal correlation of water quality parameters of produced waters from devonian-age shale following hydraulic fracturing.”	This report looks at chemical constiuents of flowback water in Pennsylvania: "Chloride was used as a reference for the comparison as its concentration varies with time of contact with the shale. Most major cations (i.e., Ca, Mg, Sr) were well-correlated with chloride concentration while barium exhibited strong influence of geographic location (i.e., higher levels in the northeast than in southwest). Comparisons against brines from adjacent formations provide insight into the origin of salinity in produced waters from Marcellus Shale. Major cations exhibited variations that cannot be explained by simple dilution of existing formation brine with the fracturing fluid, especially during the early flowback water production when the composition of the fracturing fluid and solid-liquid interactions influence the quality of the produced water. Water quality analysis in this study may help guide water management strategies for development of unconventional gas resources."
(Chapman et al. 2012)	“Geochemical and strontium isotope characterization of produced waters from Marcellus Shale natural gas extraction.”	This report looks at strontium as a key tracer isotope. "Mixing models indicate that Sr isotope ratios can be used to sensitively differentiate between Marcellus Formation produced water and other potential sources of TDS into ground or surface waters."
(Engelder, Cathles, and Bryndzia 2014)	“The fate of residual treatment water in gas shale”	This report suggests that hydraulic fracturing could actually reduce the risk of deep shale-shallow aquifer mixing: "Furthermore, contrary to the suggestion that hydraulic fracturing could accelerate brine escape and make near surface aquifer contamination more likely, hydraulic fracturing and gas recovery will actually reduce this risk. We demonstrate this in a series of STP coun- ter-current imbibition experiments on cuttings recovered from the Union SpringsMember of the Marcellus gas shale in Pennsylvania and on core plugs of Haynesville gas shale from NWLouisiana."

6.5.2 Summary of Information

The literature is mixed with different studies suggesting different potential risk factors for subsurface contamination pathways. Most studies stress that over the long-term, the unknowns are significant.

6.5.3 Analysis of Information

In general, subsurface doesn’t seem to be the most likely cause of contamination. In a risk analysis by (Rozell and Reaven 2012), they concluded that the largest risk of contamination came from wastewater disposal and a retention pond breach. Both of which are surface issues. According to the study, these risks were an order of magnitude greater than other pathways such as subsurface leaks. We explore these issues more in section 8.1. In addition, there also have been proven cases of well failure.

(Kharak et al. 2013) reported 211 groundwater contamination incidents in Texas and 183 in Ohio. According to the study, the main causes were failure of legacy wells, improper waste management and disposal, and leaks of tanks and flow lines.

To that end, evidence points to the most likely cause of subsurface contamination as faulty well construction and not migration from the source rock itself. (Darrah et al. 2014) looks at methane contamination within groundwater and using noble gas isotopes come to the conclusion that there have been cases of contamination that are most likely due to poor cementing measures in the annulus of the well. It also suggests that migration from deep shales is unlikely. Sloppy cement jobs, seismic activity, or simply poor quality cement are all possible causes.

(Engelder, Cathles, and Bryndzia 2014) looks at the fate of water left underground after treatment. This study suggests that the risks of water left underground traveling to the surface after treatment are minimal. However, the above studies mostly focus on short-term (< 1 year) impacts. (Myers 2012) looks at potential pathways of contamination that can arise over decades. This study strongly suggests that long-term monitoring methods are needed. Along these lines (Capo et al. 2014) focuses on establishing the difference between fossil waters (water present within the formation itself) and fracturing water. Namely if any migration over time were to be observed, it most likely would contain increased levels of strontium isotopes. This report and similar studies like (Barbot et al. 2013) could be potentially be used in analyses to determine any future subsurface migration issues. (Chapman et al. 2012) also explores methods to differentiate natural waters with waters related to hydraulic fracturing.

6.5.4 Conclusions and Regulations

We will address relevant cementing regulations in section 7. Below are water testing regulations and guidance documents from SB.4 and the API.

- **Relevant SB.4 Text**

  1783.3 Availability of Water Testing, Request for Water Testing.
  (a) A surface property owner notified pursuant to Section 1783.2 may request water quality testing on any existing water well or surface water located on the parcel that is suitable for drinking or irrigation purposes.

  (b) When a surface property owner makes a request for water quality testing on any water well or surface water pursuant to subdivision (a), sampling and testing shall be in accordance with the following:

(1) Water quality testing shall be performed by a Designated Contractor for Water Sampling.

(2) Water quality testing shall be conducted in accordance with the standards and protocols specified by the State Water Board pursuant to Public Resources Code section 3160, subdivision (d)(7)(B).

(3) Water quality testing shall include baseline measurements prior to the commencement of the well stimulation treatment, and follow-up measurements after the well stimulation treatment is completed.

(4) Any written request for water testing shall specify whether the surface property owner elects to select the Designated Contractor for Water Sampling and communicate directly with the contractor to arrange for testing, or, alternatively, elects to have the operator select the Designated Contractor for Water Sampling and arrange for testing.

(A) If the surface property owner elects to have the operator select and contract with the Designated Contractor for Water Sampling, the well stimulation treatment may not commence until the requested baseline water sampling is completed, provided that the request is made in writing and postmarked to the operator within 20 calendar days from the date notice is provided under section 1783.2(e) and the surface property owner makes necessary accommodations to enable the collection of baseline measurements without undue delay.

(B) If the surface property owner elects to select the Designated Contractor for Water Sampling and communicate directly with the contractor to arrange for testing, the surface property owner is responsible for scheduling baseline measurements to be taken prior to the commencement of the well stimulation treatment. The operator shall immediately inform the surface property owner when the well stimulation treatment is completed so that follow-up measurements can be collected.

(5) The operator shall pay for all reasonable costs of water quality testing under this subdivision regardless of whether the surface property owner or the operator selects and coordinates with the Designated Contractor for Water Sampling.

(6) The results of any water quality testing shall be provided to the Division, the appropriate Regional Water Board, the State Water Board, the surface property owner, and any tenant notified pursuant to Section 1783.2 to the extent authorized by the tenant's lease.

(7) The Regional Water Board shall be notified at least two working days prior to collecting a sample under this section so that Regional Water Board staff may witness the

sampling.
(c) Water quality data collected under subdivision (b) shall be submitted to the Regional Water Board in an electronic format that follows the guidelines detailed in California Code of Regulations, title 23, chapter 30.
(d) A tenant notified pursuant to Section 1783.2 that has lawful use of any existing water well or surface water located on the parcel that is suitable for drinking or irrigation purposes may independently contract with a Designated Contractor for Water Sampling for water quality testing of such water. A tenant that contracts for such testing is responsible for scheduling baseline measurements to be taken prior to the commencement of the well stimulation treatment. A tenant that contracts for water testing pursuant to this section is not entitled to reimbursement from the operator for the costs of such testing. If the operator is made aware of the tenant's contracting for water quality testing, then the operator shall immediately notify the tenant when the well stimulation treatment is completed so that follow-up measurements can be collected.

1784.1. Pressure Testing Prior to Well Stimulation Treatment.

(a) The operator shall conduct pressure testing not more than 30 days before commencing well stimulation treatment, but after all operations that could affect well integrity or the integrity of the equipment are complete. Pressure testing shall include the following:
(1) All cemented casing strings and all tubing strings to be utilized in the well stimulation treatment operations shall be pressure tested for at least 30 minutes at a pressure equal to at least 100% of the maximum surface pressure anticipated during the well stimulation treatment, but not greater than the API rated minimum internal yield of the tested casing. The operator shall chart the pressure testing. If during testing, and after equilibrium has been reached, there is a pressure change of 10% or more from the original test pressure, then the operator shall immediately notify the Division, the operator shall provide the Division with copies of the charting of the pressure testing, and the tested casing or tubing shall not be used until the cause of the pressure drop is identified and corrected to the Division's satisfaction. No casing or tubing shall be used unless it has been successfully tested pursuant to this section.

(2) All surface equipment to be utilized for well stimulation treatment shall be rigged up as designed. The pump, and all equipment downstream from the pump, shall be pressure tested at a pressure equal to 125% of the maximum surface pressure anticipated during the well stimulation treatment, but not greater than the manufacturer's pressure rating for the equipment being tested. If during testing there is a pressure change of 10% or more from the original test pressure, then the operator shall immediately notify the Division, and the tested equipment shall not be used until the cause of the pressure change is identified and corrected to the Division's satisfaction. No equipment shall be used unless it has been successfully tested pursuant to this section.

(b) The operator shall notify the Division at least 24 hours prior to conducting the pressure testing required under subdivision (a) so that Division staff may witness. The charting of pressure testing required under subdivision (a)(1) shall be provided to the Division not less than 12 hours before commencing well stimulation treatment.

1787. Well Monitoring After Well Stimulation Treatment.

(a) In advance of conducting well stimulation treatment, but at least 48 hours after cement placement, the operator shall run a radial cement evaluation log or other cement evaluation method that is approved by the Division , and the cement evaluation shall demonstrate the following:

(1) The well was and continues to be cemented in accordance with the requirements of Section 1722.4 if it is an onshore well, or Section 1744.3 if it is an offshore well; and (2) The quality of the cement is sufficient to ensure the geologic and hydrologic isolation of the oil and gas formation during and following well stimulation treatment.

(b) Documentation of the cement evaluation shall be provided to the Division not less than 72 hours before commencement of the well stimulation treatment. If the Division identifies a concern with the cement evaluation, the well stimulation treatment shall not commence until the concern has been addressed to the Division's satisfaction

(c) The Division may approve an alternate cement evaluation plan that waives the requirements of subdivisions (a) and (b) if the Division is satisfied that, based on geologic and engineering information available from previous drilling or producing operations in the area where the well stimulation treatment will occur, well construction and cementing methods have been established that ensure that there will be no voids in the annular space of the well. A request for approval of an alternate cement evaluation plan shall be submitted to the Division as part of the application for a permit to perform well stimulation treatment submitted under Section 1783.

(a) Operators shall monitor each well that has had a well stimulation treatment as specified in subdivision (d) to identify any indication of a well breach. If monitoring indicates that a well breach may have occurred, then the operator shall perform diagnostic testing on the well to determine whether a breach has occurred. Diagnostic testing shall be done as soon as is reasonably practical. The Division shall be notified when diagnostic testing is being done so that Division staff may witness the testing. All diagnostic testing results shall be immediately provided to the Division.

(b) If diagnostic testing reveals that a breach has occurred, then the operator shall immediately shut-in the well, isolate the perforated interval, and notify the Division and the Regional Water Board with all of the following information:

(1) A description of the activities leading up to the well breach.

(2) Depth interval of the well breach and methods used to determine the depth interval.

(3) An exact description of the chemical constituents of the fluid that is most representative of the fluid composition in the well at the time of the well breach.

(c) The operator shall not resume operation of a well that has been shut-in under subdivision (b) without first obtaining approval from the Division.

(d) Operators shall adhere to the following requirements for a well that has had a well stimulation treatment:
(1) The production pressure of the well shall be monitored at least once every two days for the first thirty days after the well stimulation treatment and on a monthly basis thereafter. Information regarding production pressures shall be reported to the Division on a monthly basis.
(2) The annular pressures of the well shall be reported to the Division annually, unless it has been demonstrated to the Division's satisfaction that there are no voids in the annular space. It shall be immediately reported to the Division if annular pressure exceeds 70% of the API rated minimum internal yield or collapse strength of casing, or if surface casing pressures exceed a pressure equal to: 0.70 times 0.433 times the true vertical depth of the surface casing shoe (expressed in feet).
(3) The annular valve shall be kept accessible from the surface or left open and plumbed to the surface with a working pressure gauge unless it has been demonstrated to the Division's satisfaction that there are no voids in the annular space.
(4) A properly functioning pressure relief device shall be installed on the annulus between the surface casing and the production casing, or, if intermediate casing is set, on the annuli between the surface casing and the intermediate casing and the production casing. This requirement may be waived by the Division, if the operator demonstrates to the Division's satisfaction that the installation of a pressure relief device is unnecessary based on technical analysis and/or operating experience in the area.
(5) If a pressure relief device is installed, then all pressure releases from the device shall be immediately reported to the Division. The maximum set pressure of a surface casing pressure relief device shall be the lowest of the following:

(A) A pressure equal to: 0.70 times 0.433 times the true vertical depth of the surface casing shoe (expressed in feet);

(B) 70% of the API rated minimum internal yield for the surface casing; or

(C) A pressure change that is 20% or greater than the calculated pressure increase due to pressure and/or temperature expansion

- **Relevant API Standard**
  American Petroleum Institute. *API HF2, Water Management Associated with Hydraulic Fracturing, First Edition/June 2010*. URL: `http://www.api.org/policy-and-issues/policy-items/hf/api\_hf2\_water\_management.aspx` (visited on 01/26/2015)

6.6 Surface Contamination Pathways

Spills, leaks and accidental releases, are far more common potential pathways of contamination. (Vidic et al. 2013) and (Vengosh et al. 2013) provide a very good summation and they build on a multitude of previous works and state that there is little evidence of shallow-water chemical contamination, strong evidence for methane contamination, some evidence for deep-water shallow-water aquifer mixing, and significant issues regarding produced water management and accidental spills.

6.6.1 Information Sources

(Vidic et al. 2013)	"Impact of shale gas development on regional water quality."	This report: "review[s] the current understanding of environmental issues associated with unconventional gas extraction. Improved understanding of the fate and transport of contaminants of concern and increased long-term monitoring and data dissemination will help manage these water-quality risks today and in the future."
(Vengosh et al. 2013)	"The Effects of Shale Gas Exploration and Hydraulic Fracturing on the Quality of Water Resources in the United States"	This looks at key risk pathways and suggests ways to trace contamination: "This paper provides key observations for the potential risks of shale gas drilling and hydraulic fracturing on the quality of water resources and include: (1) stray gas contamination of shallow groundwater overlying shale gas basins; (2) pathways and hydraulic connectivity between the deep shale gas formations and the overlying shallow drinking water aquifers; and (3) inadequate disposal of produced and flowback waters associated with shale gas exploration that causes contamination of surface waters and long-term ecological effects. By using geochemical (e.g., Br/Cl) integrated with oxygen, hydrogen, strontium, radium, and boron isotopic tracers, we have characterized the geochemical fingerprints of brines from several shale gas basins in the USA, including the Utica and Marcellus brines in the Appalachian Basin and the Fayetteville brines in Arkansas. We use these geochemical fingerprints to delineate the impact of shale gas associated fluids on the environment."
(Soraghan 2014)	*OIL AND GAS: Spills up 17 percent in U.S. in 2013 - Data*	This is data collected by Mike Soraghan that looks at spills from oil and gas development in the United States.

6.6.2 Summary of Information

Spill information is plentiful and most states collect it. Surface water may be contaminated through spills that occur during different stages of high volume hydraulic fracturing activities. These spills consist mainly of: discharges of wastewater to surface streams, discharges of wastewater to treatment plants, and, accidental leaks during the management of well site wastewater (returned fracturing fluid (flow-back) and produced water) site-contaminated runoff. However the management and mediation of these risks need to be incorporated into systematic approaches.

6.6.3 Analysis of Information

Below displays some indications of the volumes and incidents of spills across the United States. The data is sourced from various oil and gas regulatory agencies and has been made available by (Soraghan 2014). As FracFocus has been subject to data quality issues, so to has the below data. Figure 10 and table 22 should be taken as a magnitude estimate rather than an exact number.

Figure 10: Total Amount Spilled from 2009-2013 (Cubic Meters), (Soraghan 2014)

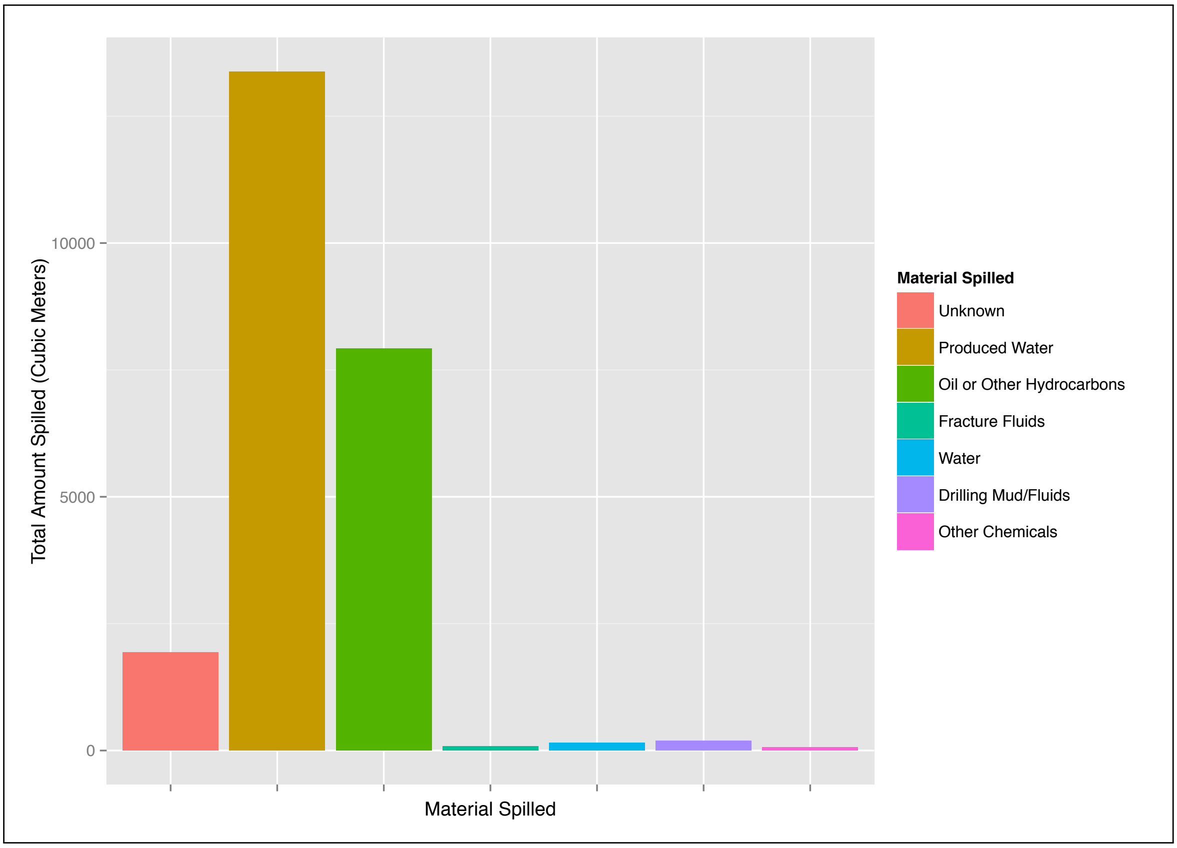


Table 22: Amount Spilled per Incident (Cubic Meters), (Soraghan 2014)

Spill Material	Min.	1st Qu.	Median	Mean	3rd Qu.	Max.
Unknown	NA	0.7949	3.1800	26.9400	17.3300	2385.0000
Produced Water	NA	1.59	4.77	20.06	15.90	10490.00
Oil or Other Hydrocarbons	NA	1.113	3.180	9.452	9.539	1590.000
Fracture Fluids	0.1510	0.7552	2.0670	8.0020	5.9620	110.0000
Water	0.159	1.431	2.862	10.130	7.949	159.000
Drilling Mud/Fluids	0.00159	0.47700	1.59000	6.04200	3.18000	365.70000
Other Chemicals	0.00318	0.79490	2.14600	12.38000	4.77000	318.00000

6.6.4 Conclusions and Regulations

The two key aspects are handling regulations and reporting requirements, in addition to adhering to relevant API technical standards for storage infrastructure. Below are the relevant reporting regulations from Texas, California, and STRONGER documentation.

- **Relevant State Law - Texas:**

  RULE §3.20 Notification of Fire Breaks, Leaks, or Blow-outs

  (a) General requirements: (1) Operators shall give immediate notice of a fire, leak, spill, or break to the appropriate commission district office by telephone or telegraph. Such notice shall be followed by a letter giving the full description of the event, and it shall include the volume of crude oil, gas, geothermal resources, other well liquids, or associated products lost.

  (2) All operators of any oil wells, gas wells, geothermal wells, pipelines receiving tanks, storage tanks, or receiving and storage receptacles into which crude oil, gas, or geothermal resources are produced, received, stored, or through which oil, gas, or geothermal resources are piped or transported, shall immediately notify the commission by letter, giving full details concerning all fires which occur at oil wells, gas wells, geothermal wells, tanks, or receptacles owned, operated, or controlled by them or on their property, and all such persons shall immediately report all tanks or receptacles struck by lightning and any other fire which destroys crude oil, natural gas, or geothermal resources, or any of them, and shall immediately report by letter any breaks or leaks in or from tanks or other receptacles and pipelines from which oil, gas, or geothermal resources are escaping or have escaped. In all such reports of fires, breaks, leaks, or escapes, or other accidents of this nature, the location of the well, tank, receptacle, or line break shall be given by county, survey, and property, so that the exact location thereof can be readily located on the ground. Such report shall likewise specify what steps have been taken or are in progress to remedy the situation reported and shall detail the quantity (estimated, if no accurate measurement can be obtained, in which case the report shall show that the same is an estimate) of oil, gas, or geothermal resources, lost, destroyed, or permitted to escape. In case any tank or receptacle is permitted to run over, the escape thus occurring shall be reported as in the case of a leak. (Reference Order Number 20-60,399, effective 9-24-70.)

  (b) The report hereby required as to oil losses shall be necessary only in case such oil loss exceeds five barrels in the aggregate.

  (c) Any operation with respect to the pickup of pipeline break oil shall be done subject to the following provisions. The provisions hereafter set out shall not apply to the picking up and the returning of pipeline break oil to the pipeline from which it escaped either at the place of the pipeline break, or at the nearest pipeline station to the break where facilities are available to return such oil to the pipeline; provided, that such operations are conducted by the pipeline operator at the time of the pipeline break and its repair; provided, further, that such authority as is herein granted for the picking up of pipeline break oil shall not relieve the operator of such pipeline of notifying the commission of such pipeline break, and the furnishing to the commission of the information required by the provisions set out in subsection (a) of this section for reporting such pipeline breaks.

(1) Any person desiring to pick up, reclaim, or salvage pipeline break oil, other than as provided in this subsection, shall obtain in writing a permit before commencing operations. All applications for permits to pick up, reclaim, or salvage such oil shall be made in writing under oath to the district office.

(2) Applications to pick up, reclaim, or salvage pipeline break oil shall state the location of such oil, the location of the break in the pipeline causing the leakage of such oil, the name of the pipeline, the owner thereof, and the date of the break.

(3) Pipeline break oil that is not returned to the pipeline from which it escaped shall be offered to the applicant to reclaim by the operator of such pipeline but shall be charged to such pipeline stock account.

- **Relevant SB.4 Text:**

1786. Storage and Handling of Well Stimulation Treatment Fluids and Wastes.
...
(5) In the event of an unauthorized release, the operator shall immediately implement the Spill Contingency Plan; notify the Regional Water Board and any other appropriate response entities for the location and the type of fluids involved, as required by all applicable federal, state, and local laws and regulations; and shall perform clean up and remediation of the area, and dispose of any cleanup or remediation waste, as required by all applicable federal, state, and local laws and regulations.

- **STRONGER Recommendation:**

4.2.1.2. Reporting capabilities
The state should provide mechanisms for operators or the public to report spills and unauthorized releases. These mechanisms should include telephone access 24 hours a day, 7 days a week. A single point of contact 1-800 telephone number should be considered. Telephone answering capabilities should include provisions for the prompt notification of appropriate state agency personnel.

7 Well Integrity Issues and Infrastructure

Given its importance in protecting the environment, this report focuses the next section on well integrity issues and relevant storage and transportation infrastructure. Poor management of these two issues is seen as one of the potentially weakest links in oil and gas environmental management.

7.1 Well Integrity Issues

Underground, the key barrier between hydraulic fracturing fluids and hydrocarbons is the well lining itself. This is seen as the most likely point of failure within the subsurface system.

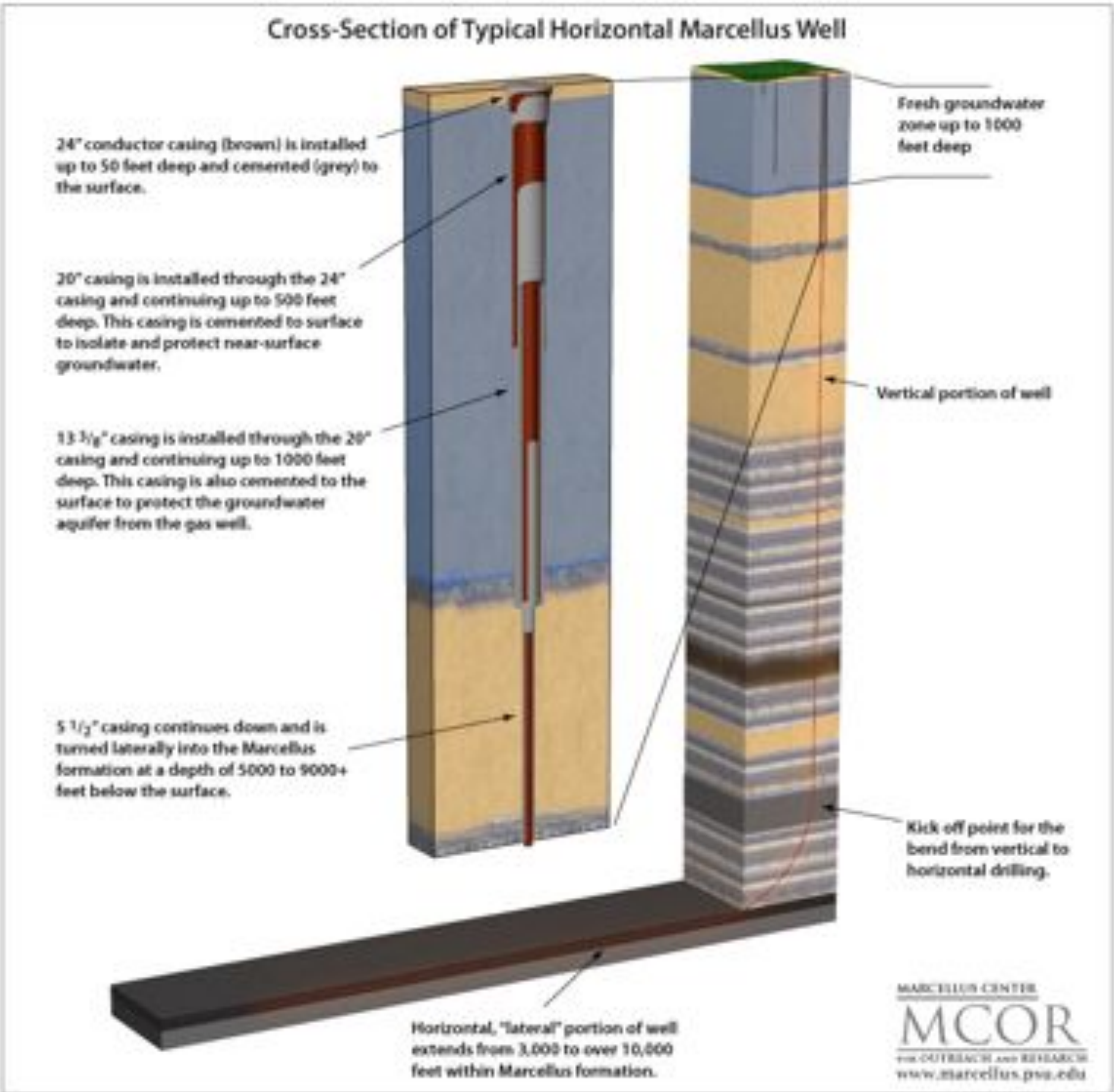
7.1.1 Information Sources

(Davies et al. 2014)	“Oil and gas wells and their integrity: Implications for shale and unconventional resource exploitation”	This study collects well data failure. "Of the 8030 wells targeting the Marcellus shale inspected in Pennsylvania between 2005 and 2013, 6.3% of these have been reported to the authorities for infringements related to well barrier or integrity failure. In a separate study of 3533 Pennsylvanian wells monitored between 2008 and 2011, there were 85 examples of cement or casing failures, 4 blowouts and 2 examples of gas venting. In the UK, 2152 hydrocarbon wells were drilled onshore between 1902 and 2013 mainly targeting conventional reservoirs. UK regulations, like those of other jurisdictions, include reclamation of the well site after well abandonment. As such, there is no visible evidence of 65.2% of these well sites on the land surface today and monitoring is not carried out. The ownership of up to 53% of wells in the UK is unclear; we estimate that between 50 and 100 are orphaned. Of 143 active UK wells that were producing at the end of 2000, one has evidence of a well integrity failure"

7.1.2 Summary and Analysis of Information

Normally there are several layers points of protection between the contents of the well and any aquifer as seen in figure 11. However these wells have been shown to fail.

Figure 11: Marcellus Shale Example, (Penn State 2014)



For data on well failures (Davies et al. 2014) looks at well cementing integrity in actual wells and aggregates failure data across studies. It is a key study for actual data of well failures. We have reproduced some of the relevant data below:

Table 24: Data on Well Failure Incidents, (Davies et al. 2014)

Country	Location	No. Wells Studied	% Wells with Barrier Failure or Well Integrity Failure	Additional Information	Published Source
USA	Ann Mag Field, South Texas, USA (1998-2011)	18	61	Wells drilled 1998-2011.	Yuan et al. (2013)
USA	Marcellus Shale	8030	6.26	Well reports 2005-2013. 1.27% leak to surface.	(Davies et al. 2014)
USA	Marcellus Shale (2010-2012)	4602	4.8	Wells drilled 2010-2012.	Ingraffea (2012)
Canada	Alberta (1910-2004)	316,439	4.6	Wells drilled 1910-2004. Monitored 1970-2004.	Watson and Bachu (2009)
USA	Marcellus Shale (2008-2013)	6466	3.4	Wells drilled 2005-2012. Leak to surface in 0.24% wells.	Vidic et al. (2013)
USA	Marcellus Shale (2008-2011)	3533	2.58	Wells drilled 2008-2011.	Considine et al. (2013)

It seems that modern shale wells have a well integrity failure rate roughly between 2-6%. With well numbers in the tens of thousands, we can assume that well failures are not an unusual event.

7.1.3 Conclusion and Regulations

As such we see well cementing and integrity regulations as key in any oil and gas development. Suggestions to ameliorate these impacts consist of ensuring adequate 3rd party enforcement, adhering to API standards, and submitting pre-and post completion cement tests. Below we include relevant regulation from Pennsylvania, SB.4, and some relevant API standards.

- **Relevant State Regulations - Pennsylvania:**

  §78.83. Surface and coal protective casing and cementing procedures.

  (a) For wells drilled, altered, reconditioned or recompleted after February 5, 2011, surface casing or any casing functioning as a water protection casing may not be utilized as production casing unless one of the following applies:

(1) In oil wells where the operator does not produce any gas generated by the well and the annulus between the surface casing and the production pipe is left open.
(2) The operator demonstrates that the pressure in the well is no greater than the pressure permitted under 78.73(c) (relating to general provision for well construction and operation), demonstrates through a pressure test or other method approved by the Department that all gas and fluids will be contained within the well, and installs a working pressure gauge that can be inspected by the Department.

(b) If the well is to be equipped with threaded and coupled casing, the operator shall drill a hole so that the diameter is at least 1 inch greater than the outside diameter of the casing collar to be installed. If the well is to be equipped with plain-end welded casing, the operator shall drill a hole so that the diameter is at least 1 inch greater than the outside diameter of the casing coupling.

(c) The operator shall drill to approximately 50 feet below the deepest fresh groundwater or at least 50 feet into consolidated rock, whichever is deeper, and immediately set and permanently cement a string of surface casing to that depth. Except as provided in subsection (f), the surface casing may not be set more than 200 feet below the deepest fresh groundwater except if necessary to set the casing in consolidated rock. The surface hole shall be drilled using air, freshwater, or freshwater-based drilling fluid. Prior to cementing, the wellbore shall be conditioned to ensure an adequate cement bond between the casing and the formation. The surface casing seat shall be set in consolidated rock. When drilling a new well or redrilling an existing well, the operator shall install at least one centralizer within 50 feet of the casing seat and then install a centralizer in intervals no greater than every 150 feet above the first centralizer.

(d) The operator shall permanently cement the surface casing by placing the cement in the casing and displacing it into the annular space between the wall of the hole and the outside of the casing.

(e) Where potential oil or gas zones are anticipated to be found at depths within 50 feet below the deepest fresh groundwater, the operator shall set and permanently cement surface casing prior to drilling into a stratum known to contain, or likely containing, oil or gas.

(f) If additional fresh groundwater is encountered in drilling below the permanently cemented surface casing, the operator shall document the depth of the fresh ground water zone in the well record and protect the additional fresh groundwater by installing and cementing a subsequent string of casing or other procedures approved by the Department to completely isolate and protect fresh groundwater. The string of casing may also penetrate zones bearing salty or brackish water with cement in the annular space being used to segregate the various zones. Sufficient cement shall be used to cement the casing to the surface. The operator shall install at least one centralizer within 50 feet of the casing seat and then install a centralizer in intervals no greater than, if possible, every 150 feet above the first centralizer.

(g) The operator shall set and cement a coal protective string of casing through workable coal seams. The base of the coal protective casing shall be at least 30 feet below the lowest workable coal seam. The operator shall install at least two centralizers. One centralizer shall be within 50 feet of the casing seat and the second centralizer shall be within 100 feet of the surface.

(h) Unless an alternative method has been approved by the Department in accordance with § 78.75 (relating to alternative methods), when a well is drilled through a coal seam at a location where the coal has been removed or when a well is drilled through a coal pillar, the operator shall drill to a depth of at least 30 feet but no more than 50 feet deeper than the bottom of the coal seam. The operator shall set and cement a coal protection string of casing to this depth. The operator shall equip the casing with a cement basket or other similar device above and as close to the top of the coal seam as practical. The bottom of the casing must be equipped with an appropriate device designed to prevent deformation of the bottom of the casing. The interval from the bottom of the casing to the bottom of the coal seam shall be filled with cement either by the balance method or by the displacement method. Cement shall be placed on top of the basket between the wall of the hole and the outside of the casing by pumping from the surface. If the operator penetrates more than one coal seam from which the coal has been removed, the operator shall protect each seam with a separate string of casing that is set and cemented or with a single string of casing which is stage cemented so that each coal seam is protected as described in this subsection. The operator shall cement the well to isolate workable coal seams from each other.

(i) If the operator sets and cements casing under subsection (g) or (h) and subsequently encounters additional fresh groundwater zones below the deepest cemented casing string installed, the operator shall protect the fresh groundwater by installing and cementing another string of casing or other method approved by the Department. Sufficient cement shall be used to cement the casing to the surface. The additional casing string may also penetrate zones bearing brackish or salt water, but shall be run and cemented prior to penetrating a zone known to or likely to contain oil or gas. The operator shall install at least one centralizer within 50 feet of the casing seat and then, if possible, install a centralizer in intervals no greater than every 150 feet above the first centralizer.

(j) If it is anticipated that cement used to permanently cement the surface casing cannot be circulated to the surface a cement basket may be installed immediately above the depth of the anticipated lost circulation zone. The casing shall be permanently cemented by the displacement method. Additional cement may be added above the cement basket, if necessary, by pumping through a pour string from the surface to fill the annular space. Filling the annular space by this method does not constitute permanently cementing the surface or coal protective casing under Âğ 78.83b (relating to casing and cementing-lost circulation).

Source: The provisions of this Âğ 78.83 adopted July 28, 1989, effective July 29, 1989, 19 Pa.B. 3229; amended March 6, 1998, effective March 7, 1998, 28 Pa.B. 1234; amended February 4, 2011, effective February 5, 2011, 41 Pa.B. 805. Immediately preceding text appears at serial pages (276328) to (276330).

- **Relevant SB.4 Text**

1782. General Well Stimulation Treatment Requirements.
(a) When a well stimulation treatment is performed, the operator shall ensure that all of the following conditions are continuously met:
(1) Casing is sufficiently cemented or otherwise anchored in the hole in order to effectively control the well at all times;
(2) Geologic and hydrologic isolation of the oil and gas formation are maintained during and following the well stimulation treatment;
(3) All potentially productive zones, zones capable of over-pressurizing the surface casing annulus, or corrosive zones be isolated and sealed off to the extent that such isolation is necessary to prevent vertical migration of fluids or gases behind the casing;

(4) All well stimulation treatment fluids are directed into the zone(s) of interest;
(5) The wellbore's mechanical integrity is tested and maintained;
(6) The well stimulation treatment fluids used are of known quantity and description for reporting and disclosure as required pursuant to this article; and
(7) The well stimulation treatment will not damage the well casing, tubing, cement, or other well equipment, or would not otherwise cause degradation of the well's mechanical integrity during the treatment process;
(8) Well breach occurring during well stimulation treatment will be reported as required in Section 1785, subdivision (d); and
(9) Well stimulation treatment operations are conducted in compliance with all applicable requirements of the Regional Water Board, the Department of Toxic Substances Control, the Air Resources Board, the Air Quality Management District or Air Pollution Control District, the Certified Unified Program Agency, and any other local agencies with jurisdiction over the location of the well stimulation activities.

- **Relevant API Standards:**

-API Guidance Document HF1, Hydraulic Fracturing Operations- Well Construction and Integrity Guidelines - API Specification 5B, Specification for Threading, Gauging,

and Thread Inspection of Casing, Tubing, and Line Pipe Threads
- API Specification 5CT/ISO 11960, Specification for Casing and Tubing
- API Specification 10A/ISO 10426-1, Specification for Cements and Materials for Well Cementing
- API Recommended Practice 10B-2/ISO 10426-2, Recommended Practice for Testing Well Cements
- API Recommended Practice 10D-2/ISO 10427-2, Recommended Practice for Centralizer Placement and Stop Collar Testing
- API Technical Report 10TR1, Cement Sheath Evaluation
- API Technical Report 10TR4, Technical Report on Considerations Regarding Selection of Centralizers for Primary Cementing Operations - API Recommended Practice 65-2, Isolating Potential Flow Zones During Well Construction *NOTE API RP 65-2 was under development at the time of publication of API HF1. However, given its subject matter, API felt is was appropriate to include as a reference. API RP 65-2 will provide guidance on well planning, drilling and cementing practices, and formation integrity pressure testing. Upon publication, API RP 65-2 will be available at www.api.org/publications, and will serve as a valuable reference for use in conjunction with API HF1.*
- API Standard Recommended Practice 90, Annular Casing Pressure Management for Offshore Wells

- **Relevant STRONGER Guideline:**

  9.2.1. Standards
  State programs for hydraulic fracturing should include standards for casing and cementing to meet anticipated pressures and protect resources and the environment. The state should have the authority as necessary to require the conduct or submittal of diagnostic logs or alternative methods of determining well integrity. The state program should address the identification of potential conduits for fluid migration in the area of hydraulic fracturing and the management of the extent of fracturing where appropriate. The program should require monitoring and recording of annular pressures during hydraulic fracturing operations. The program also should address actions to be taken by the operator in response to operational or mechanical changes that may cause concern, such as significant deviation from the fracture design and significant changes in annular pressures.

7.2 Infrastructure

7.2.1 Information Sources

As wells can fail, so can infrastructure such as pits, pipelines, and tanks. The data on these failures is not available. In this section we will discuss the environmental risks from produced water infrastructure including open pits, tanks, and roads and pipelines. The most primary of which are the risks associated with open pits. As the water demand of hydraulic fracturing is significant, but temporary, it does not make sense for many operators to install permanent water storage infrastructure.

(Proctor 2013)	*Colorado flood-related oil spills total nearly 43,000 gallons - Denver Business Journal*	The article looks at the spills resulting from 2013 floods in Colorado.

7.2.2 Summary of Information

The literature on infrastructure is not extensive. This report will look at specific accidents and will suggest API regulations to fill this gap.

7.2.3 Analysis of Information

In lieu of permanent infrastructure, many operators will dig pits in the ground, line them with plastic or vinyl sheets, and use them to store water both before and after the hydraulic fracturing job. These pits can leak and subsequently can kill aquatic life. In fact, the highest ever fine levied against an operator is for 4.5 million against a Pennsylvania operator whose pits leaked (*Pa. DEP Seeks $4.5M Fine Against EQT Over Fracking Spill - Law360*).

In addition to massive volumes of fluids that need to be stored on-site, chemicals and additives involved in the hydraulic fracturing process also need to be stored and transported safely. These chemicals should be handled and transported according to general hazardous materials regulations and standards (NYSDEC 2011).

Long-term, permanent infrastructure needs to be installed in order to collect water coproduced along with oil and gas. These are usually large metal tanks that store volumes of water up to several hundred barrels at a time, however pipeline systems also exist where drilling densities are sufficient. These tanks however can leak and fail. In addition, extreme events such as flooding can also cause them to fail and result in spills of hydraulic fracturing fluid and hydrocarbons, this was demonstrated by the 2013 floods in Colorado where an estimated 162 cubic meters of hydrocarbons and produced water spilled (Proctor 2013).

7.2.4 Conclusions and Regulations

Below are aggregated some examples of regulations related to infrastructure in Michigan, API standards, and references to relevant STRONGER guidelines.

- **Relevant State Regulation - Michigan:**
  R 324.407 Drilling mud pits.

Rule 407. (1) The supervisor shall prohibit the use of a drilling mud pit if it is determined that the mud pit causes waste.
(2) Drill cuttings, muds, and fluids shall be confined by a pit, tank, or container which is of proper size and construction and which is located as approved by the supervisor or authorized representative of the supervisor.
(3) Only tanks shall be utilized while drilling a well that is located in an area zoned residential before January 8, 1993. The supervisor may grant an exception if the applicant or permittee makes a request for an exception as part of the written application for a permit. The supervisor may grant an exception if an applicant or permittee satisfactorily demonstrates that a municipal water system is utilized or required to be utilized.
(4) Drilling mud pits shall be located and plotted as instructed by the supervisor. Before construction of the mud pit, a permittee shall demonstrate to the supervisor or authorized representative of the supervisor that there is not less than 4 feet of vertical isolation between the bottom of the pit and the uppermost groundwater level. The bottom of the liner shall not be installed within the observed groundwater level as determined while excavating the pit. If groundwater is encountered during or before construction of the pit, then the permittee shall select 1 of the following options and obtain the approval for the option from the supervisor or authorized representative of the supervisor:

(a) The pit shall be designed and constructed so the bottom of the pit is not less than 4 feet above the groundwater level.

(b) The pit shall be designed and constructed so the bottom of the pit is above the groundwater level, but less than 4 feet above the groundwater level, and during encapsulation the pit contents shall be solidified using a method approved by the supervisor.

(c) The pit shall be relocated at the well site as approved by the supervisor or authorized representative of the supervisor.

(d) Tanks shall be used, and drilling muds disposed of, at an approved off-site location.
(5) Drilling mud pits shall be constructed as instructed by the supervisor and shall be in compliance with both of the following minimum requirements:

(a) Pits shall be constructed with rounded corners and side slopes of not less than 20 degrees measured from the vertical.

(b) The bottom and sides of the pit shall be free of objects that could penetrate the liner.
(6) Drilling mud pits shall be lined as instructed by the supervisor and shall be in compliance with all of the following minimum requirements:

(a) Pits shall be lined with 20-mil virgin polyvinyl chloride liners as approved by the supervisor or with other liners that meet or exceed the 20-mil virgin polyvinyl chloride liner requirement.

- **Relevant API Standard**
  RP 5A3/ISO 13678:2010 - Recommended Practice on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (includes Errata 1 dated April 2011)

  -Spec 12B Specification for Bolted Tanks for Storage of Production Liquids

-Spec 12D Specification for Field Welded Tanks for Storage of Production Liquids

-Many more specific regulations can be found here `http://www.api.org/~/media/files/publications/catalog/1_exploration_production.pdf`

- **Relevant STRONGER Guideline**
  5.9.1. Scope
  a. This section applies to permanently installed E&P waste tanks and to produced water storage tanks located at enhanced recovery operations. Where some waste tanks are regulated under the Spill Prevention Control and Countermeasures (SPCC) requirements of the federal Clean Water Act, states may defer to the SPCC requirements for those tanks.
  b. Except as provided in Section 5.9.3.b., this section does not apply to:

  i. condensate and crude oil tanks;

  ii. process vessels, such as separators, heater treaters, dehydrators or freewater knockouts, except that stacks or vents on such vessels should be equipped, where necessary, to protect migratory birds and other wildlife; and

  iii. tanks used temporarily in drilling and workover operations. c. The regulatory agency may adjust or exempt from the requirements of this section small-capacity tanks.

  5.9.2. General Requirements
  a. States should have information, where available, on the locations, use, capacity, age and construction materials (e.g., steel, fiberglass, etc.) of tanks as needed to administer and enforce state program requirements effectively. Such information may be obtained through registrations, inventories, or other appropriate means. b. Tanks covered by this section should not be located in a flowing or intermittent stream and should be sited consistent with applicable local land-use requirements. c. Tanks should be subject to spill-prevention, preventive maintenance and inspection requirements, including those of Sections 5.3.1.c. and 5.3.3.

  5.9.3. Construction and Operation Standards
  a. A principal goal of construction and operation standards for tanks is to minimize the occurrence of and the environmental impacts from spills and leaks.

  i. New tanks should be constructed in a manner that provides for corrosion protection consistent with the intended use of the tanks. All tanks covered by this section should be operated in a manner that provides for corrosion protection consistent with the use of the tanks.

  ii. Tanks should exhibit structural integrity consistent with their intended use. Wooden tanks should receive increased scrutiny in this regard.

  iii. Tanks should be operated in a manner that protects against overtopping.

  iv. Secondary containment systems or other appropriate means, such as leak detection, should be employed to minimize environmental impacts in the event of releases. b. Covered tanks are preferred to open tanks. Open E&P waste and product tanks should be equipped to protect migratory birds and other wildlife in a manner consistent with the wildlife-protection criterion of

Section 5.5.3.f.
c. Tanks located in populated areas where emissions of hydrogen sulfide can be expected should be equipped with appropriate warning devices.

5.9.4. Tank Removal and Closure
a. Tanks should be emptied prior to their retirement and the resulting materials should be managed properly.
b. Tanks and associated above ground equipment should be removed upon cessation of operations. For good cause, a state may allow tanks to be removed as soon as practical thereafter. Site reclamation should meet all landowner and lease obligations and any other applicable requirements.
c. Prior to removal, closure, or release for unrestricted use, tanks and associated piping and equipment should be surveyed for NORM as provided for in Section 7. When regulatory action levels are exceeded, NORM and the equipment containing NORM should be managed in accordance with the state's NORM regulatory program (see Section 7 of these guidelines).

8 Waste Impacts

The primary wastes of concern from oil and gas developments are: drilling fluids and muds; drill cuttings; produced water; fracturing fluid returns; and naturally occurring radioactive materials (NORM). This report separates these wastes into two categories, produced water and other liquid waste, and solid wastes, both of which will be analyzed in terms of their disposal and management options.

In general, different disposal methods and associated regulations apply depending on the level of hazard of the waste and the circumstances of the particular development. Due to EPA exemptions, many drilling wastes are not considered hazardous and therefore, they can be disposed without special management (US EPA 2014a) even though they may contain toxic materials. Whether these solids are hazardous or not, is determined by specific regulations from the U.S. EPA. In general these wastes are exempt from being treated as hazardous waste if they meet two criteria:

- "Has the waste come from down-hole, i.e., was it brought to the surface during oil and gas E&P operations?
- Has the waste otherwise been generated by contact with the oil and gas production stream during the removal of produced water or other contaminants from the product?-(US EPA 2014a)"

If the answer is yes to either question, then the wastes are exempt. This exemption has been controversial, and much debate has arisen in regards to its justification. Many environmental NGOs argue that this exemption should be reversed at the federal level (Hammer and VanBriesen 2012). As such, most waste in hydraulic fracturing developments except for hydrocarbons, pure chemicals, and radioactive materials, are not seen as hazardous.

8.1 Produced Water

Oil and gas operations co-produce large volumes of water along with oil and gas. This water is a mixture of fracture fluid, geologic water, and constituents picked up within the shale itself. The exact volume of it is determined by the characteristics and amount of water injected and the geology itself. The vast majority of this water flows back within the first two to eight weeks, but hundreds of liters of water can be produced daily during the lifetime of the well (NYSDEC 2011).

8.1.1 Information Sources

The following studies were seen as the most relevant regarding produced water management and disposal.

Source	Title	Summarized Abstract
(Acharya and Henderson 2010)	"Cost effective recovery of low-TDS frac flowback water for re-use"	This study looks at produced water treatment: "The project goal was to develop a cost-effective water recovery process to reduce the costs and envi- ronmental impact of shale gas production. This effort sought to develop both a flowback water pre- treatment process and a membrane-based partial demineralization process for the treatment of the low-Total Dissolved Solids (TDS) portion of the flowback water produced during hydrofracturing opera- tions. The TDS cutoff for consideration in this project is < 35,000 ˜ 45,000 ppm, which is the typical limit for economic water recovery employing reverse osmosis (RO) type membrane desalination processes. The ultimate objective is the production of clean, reclaimed water suitable for re-use in hydrofracturing operations."
(Boschee 2014)	*Produced and Flowback Water Recycling and Reuse*	This report reviews the major issues related to produced water and flowback from an industry perspective. It looks at costs, volumes, and treatment technologies.
(Slutz et al. 2012)	"Key Shale Gas Water Management Strategies: An Economic Assessment Tool"	"This paper will analyze the total life cycle water management costs per frac by comparing the options and costs of water supply; water transportation; cost and options for disposal, re-use, and recycling; impact of water quality on frac chemical costs; the impact of water quality on frac performance and long-term well performance. This paper will also identify other impacts, including safety, public perception, community impact, and environmental liability."
(Barbot et al. 2013)	"Spatial and temporal correlation of water quality parameters of produced waters from devonian-age shale following hydraulic fracturing."	This report looks at chemical constiuents of flowback water in Pennsylvania: "Chloride was used as a reference for the comparison as its concentration varies with time of contact with the shale. Most major cations (i.e., Ca, Mg, Sr) were well-correlated with chloride concentration while barium exhibited strong influence of geographic location (i.e., higher levels in the northeast than in southwest). Comparisons against brines from adjacent formations provide insight into the origin of salinity in produced waters from Marcellus Shale. Major cations exhibited variations that cannot be explained by simple dilution of existing formation brine with the fracturing fluid, especially during the early flowback water production when the composition of the fracturing fluid and solid-liquid interactions influence the quality of the produced water. Water quality analysis in this study may help guide water management strategies for development of unconventional gas resources."

(Gregory, Vidic, and Dzombak 2011)	"Water management challenges associated with the production of shale gas by hydraulic fracturing"	This study looks at wastewaters that contain high TDS levels are challenging and costly to treat: "Economical production of shale gas resources will require creative management of fl owback to ensure protection of groundwater and surface water resources. Currently, deep-well injection is the primary means of management. However, in many areas where shale gas production will be abundant, deep-well injection sites are not available. With global concerns over the quality and quantity of fresh water, novel water management strategies and treatment technologies that will enable environmentally sustainable and economically feasible natural gas extraction will be critical for the development of this vast energy source."
(Hayes et al. 2012)	"Barnett and Appalachian Shale water management and reuse technologies"	This report characterizes produced water, looks at re-use feasibility, alternative water sources, and various treatment options.
(McCurdy 2011)	*Proceedings of the Technical Workshops for the Hydraulic Fracturing Study: Water Resources Management*	This report summarizes technical workshops hosted by the US EPA on water resource management techniques.

8.1.2 Summary of Information

Most of the literature regarding produced water is focused on potential treatment methods and costs, and its aimed at making treatment the primary mode of disposal. The key takeaways from this body of literature are that technologies exist to treat water, however the costs of these technologies in most cases are prohibitive. Therefore, most water is currently disposed of by injecting it to underground wells. The above literature provides data on volumes, water quality, and treatment methods.

8.1.3 Analysis of Information

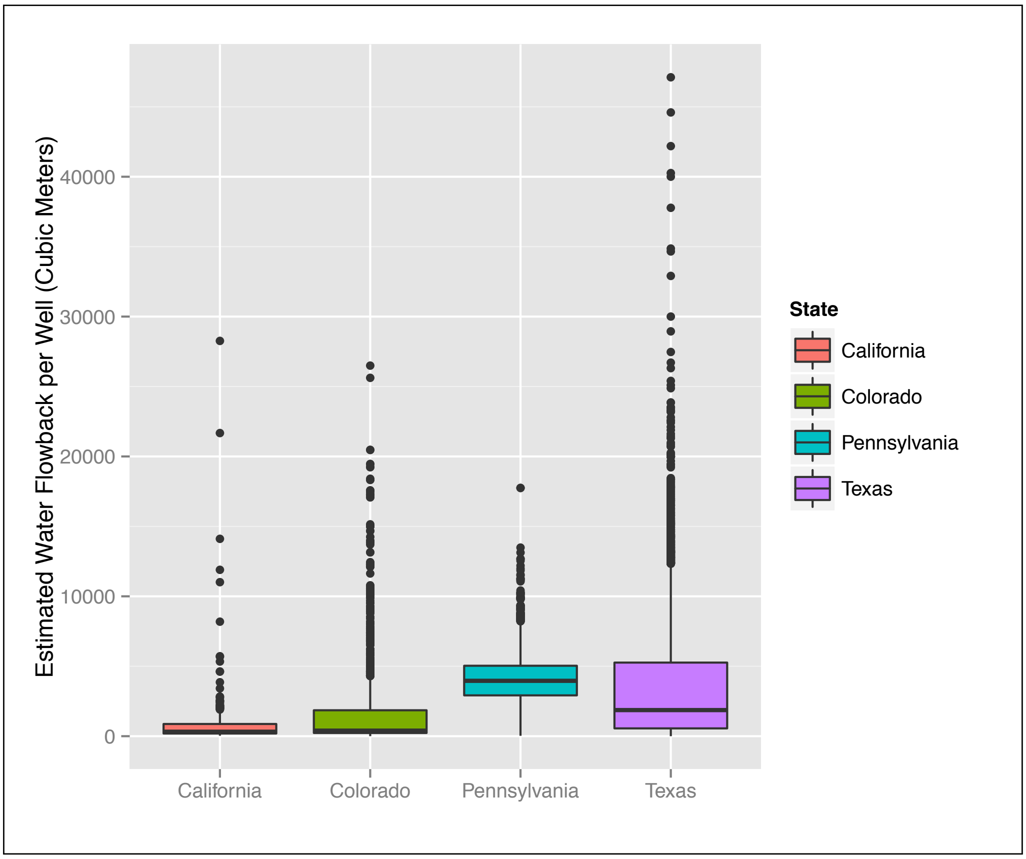
To get the total volumes of produced water involved in the U.S. this report combines (Boschee 2014) and (SkyTruth 2014) data. (Boschee 2014) show estimates for the percentage of total water that flows back. Using these percentage estimates along with the known produced water estimates from figure [Referenced in larger paper] we can roughly estimate the per-well magnitude of produced water for each state. These are shown in figure 12.

Table 27: Flowback of Water, (Boschee 2014)

Producing Area	% of Hydraulic Fracturing Fluid Returned as Flowback	% Produced Water Volumes
Bakken	15 to 40	High
Eagle Ford	<15	Low
Permian Basin	20 to 40	High
Marcellus	10 to 40	Moderate
Denver-Julesburg	15 to 30	Low

We can see that the variation is great both within plays and between plays. Note that the majority of the data comes from Texas and is thus over represented in the below summary statistics.

Figure 12: Water Flow Back Estimates (Cubic Meters Per Well)



	Minimum	1st Quartile	Median	Mean	3rd Quartile	Max.
Summary for above States	0.02385	371.6	1879	2941	4528	47110

In addition to the volume of the water, the timing of production of it is of special concern as it is not equal for the entire lifetime of the well. The majority of water is produced at the very beginning of the well's operation (within 90 days post-completion) however, as long as the well is active, it has the potential to produce water along with hydrocarbons (Hayes 2009). This means that long-term management methods and disposal infrastructure need to be in place.

Apart from volume, the quality of these produced waters is of concern. The quality of these produced water is largely determined by the geologic conditions of the plays in which it was used. Some plays will produce water with higher contaminants than others. These correlate highly with other constituents (Barbot et al. 2013) and can be taken as an indicator for overall water quality. To exhibit average water quality for various plays, we showcase TDS estimates from (Barbot et al. 2013) in table 28.

Table 28: Average TDS Found in Flowback and Produced Water, (Boschee 2014)

Producing Area	TDS (mg/L)
Bakken	150,000 to 300,000
Eagle Ford	15,000 to 55,000
Permian Basin	20,000 to 30,000
Marcellus	20,000 to 100,000
Denver-Julesburg	20,000 to 65,000

Table 28 suggests that areas like the Bakken and the Marcellus produce high-TDS harder to treat waters and plays like the Permian result in "higher-quality" water that takes less energy inputs to treat.

All water produced by oil and gas developments needs to be separated from hydrocarbons with filters or centrifuges. This process generally removes total suspended solids (TSS) and is required regardless of the planned end fate of this water (NYSDEC 2011). However, in order for produced water to be re-used for any non-oil and gas related purpose, these dissolved solids must be removed from it. This process requires significant energy and hence, poses significant costs (Gregory, Vidic, and Dzombak 2011). Due to the variability of geologies, there is no single method of produced water management. However this report analyses the most common methods used for this purpose and explores the environmental risks associated with them. Overall, cost is the key factor when deciding which treatment and management methods will be used. This cost of this methods is dependent on the quality of the water, the quantity of it, and the distance it needs to travel.

The main methods of management in order of most commonly used to least are: underground injection, recycling for future hydraulic fracturing operations, treatment through reverse osmosis, flash distillation, and treatment at a specialized centralized facility. The exact method of treatment, transport, and recycling is dependent on local conditions and regulations, existing infrastructure, and technologies utilized. (Slutz et al. 2012).

8.2 Injection

After the water is filtered, the majority of it in the U.S. is disposed by underground injection in underground injection control (UIC) wells. Except for in Pennsylvania, injection of produced water tends to be the cheapest and, therefore the most common method of produced water management (Ma, Geza, and Xu 2014).

8.2.1 Injection Information Sources

In addition to the above sources, the below studies are the most relevant regarding issues related injection issues.

Author	Title	Summarized Abstract
(Ma, Geza, and Xu 2014)	"Review of Flowback and Produced Water Management, Treatment and Beneficial Use for Major Shale Gas Development Basins"	This study evaluated the challenges and prospect of beneficial use through review of existing studies on flowback and produced water management in major shale plays. Currently, operators in Marcellus Shale are reusing over 90% of flowback and produced water, mainly for hydraulic fracturing. Barnett Shale, Eagle Ford Shale, Fayetteville Shale and Haynesville Shale, are using deep well injection as their primary disposal method. However, produced water beneficial use potential in Barnett, Eagle Ford and Fayetteville is expected high due to new regulations and water shortage due to droughts.
(US EPA 2012a)	*Class II Wells - Oil and Gas Related Injection Wells (Class II)*	This EPA report describes the various types of Class II wells and their uses. It also explains how the use of Class II wells protects drinking water resources, and presents the UIC Program requirements for Class II wells to ensure the protection of underground sources of drinking water (USDWs).
(US EPA 2001)	*Technical Program Overview: Underground Injection Control Regulations*	This document provides an overview of the minimum regulations which are the basis of the U.S. Environmental Protection Agency's (EPA) Underground Injection Control (UIC) Program. Development of these minimum standards by EPA, was required by Federal statute (Safe Drinking Water Act, signed into law December 17, 1974). Congress intended for EPA to establish a Federal- State system of regulation to assure that drinking water sources, actual and potential, are not rendered unfit for such use by underground injection of contaminants.
(Lustgarten 2012)	"Injection Wells: The Poison Beneath Us"	This article gives an overview of the injection well program in the United States. It gives examples of well failure for certain wells.

8.2.2 Summary of Information

Most of the existing literature regarding injection wells do not differentiate between hydraulic fracturing and conventional oil and gas developments. The relevant issues associated with this method are well failure and induced seismicity.

8.2.3 Analysis of Literature

There are currently 144,000 active class II injection wells in the United States (US EPA 2012a). Class II injection wells are drilled in geologic formations where it is determined that the water can be sequestered indefinitely within the formation. These wells can be specifically drilled for the purpose of disposal, but are more often converted from oil and gas wells. These wells are subject to approval by state regulators which also determine the exact pressures and volumes in which water can be injected.

8.2.4 Conclusions and Regulations

Although the exact number of failures of injection wells is unknown, the report by (Lustgarten 2012) shows that these wells fail and can cause contamination. In addition, injected fluids need to be sequestered for thousands of years and thus long-term planning poses particular complications. Moreover, this process can cause small earthquakes which will be explored in section 8.3.

It is clear that this is an area lacking sufficient research. Below, this report includes relevant technical standards and regulations in regard to disposal wells.

- **Relevant State Regulation - EPA:** US EPA (2001). *Technical Program Overview: Underground Injection Control Regulations*. Tech. rep. URL: `http://www.epa.gov/safewater/uic/pdfs/uic\_techovrview.pdf`

- **Relevant State Regulation - California: 1724.7. Project Data Requirements.**
  (Note: See Section 1724.8 for special requirements for cyclic steam projects, and Section 1724.9 or supplementary requirements for gas storage projects.) The data required to be filed with the district deputy include the following, where applicable:
  (a) An engineering study, including but not limited to:

  (1) Statement of primary purpose of the project.

  (2) Reservoir characteristics of each injection zone, such as porosity, permeability, average thickness, areal extent, fracture gradient, original and present temperature and pressure, and original and residual oil, gas, and water saturations.

  (3) Reservoir fluid data for each injection zone, such as oil gravity and viscosity, water quality, and specific gravity of gas.

(4) Casing diagrams, including cement plugs, and actual or calculated cement fill behind casing, of all idle, plugged and abandoned, or deeper-zone producing wells within the area affected by the project, and evidence that plugged and abandoned wells in the area will not have an adverse effect on the project or cause damage to life, health, property, or natural resources.

(5) The planned well-drilling and plugging and abandonment program to complete the project, including a flood-pattern map showing all injection, production, and plugged and abandoned wells, and unit boundaries.

(b) A geologic study, including but not limited to:

(1) Structural contour map drawn on a geologic marker at or near the top of each injection zone in the project area.

(2) Isopachous map of each injection zone or subzone in the project area.

(3) At least one geologic cross section through at least one injection well in the project area.

(4) Representative electric log to a depth below the deepest producing zone (if not already shown on the cross section), identifying all geologic units, formations, freshwater aquifers, and oil or gas zones.

(c) An injection plan, including but not limited to:

(1) A map showing injection facilities.

(2) Maximum anticipated surface injection pressure (pump pressure) and daily rate of injection, by well.

(3) Monitoring system or method to be utilized to ensure that no damage is occurring and that the injection fluid is confined to the intended zone or zones of injection.

(4) Method of injection.

(5) List of proposed cathodic protection measures for plant, lines, and wells, if such measures are warranted.

(6) Treatment of water to be injected.

(7) Source and analysis of the injection liquid.

(8) Location and depth of each water-source well that will be used in conjunction with the project.

- **STRONGER Guideline**
  Class II UIC programs are administered by the States where EPA has approved primary enforcement authority (primacy), or are directly implemented by EPA where the States have not sought or received approval for their UIC program. Amendments to the SDWA in 1980 further allowed a State with an existing regulatory program to obtain primary enforcement authority from EPA as long as the State was able to demonstrate that its program was effective in protecting underground sources of drinking water (USDWs), rather than adopting the complete set of Federal requirements. States with UIC program primacy receive federal funding for program implementation.
  In general, EPA determines which fluids may be injected into Class II wells in direct implementation

UIC programs. Primacy States follow their EPA approved primacy agreements in ascertaining whether specific fluids are qualified for injection into their Class II wells.
Among the minimum requirements for Class II wells are:
a. Only approved fluids may be injected,
b. No injection may endanger a USDW,
c. No well may be used for injection without a permit, unless authorized by rule.
d. All injection wells must demonstrate mechanical integrity at least once every 5 years.
Class II wells can "inject brines and other fluids associated with oil and gas production, and hydrocarbons for storage."

8.3 Seismicity

As stated before, injection of wastewater into disposal wells has been shown to cause earthquakes. A study conducted by (Ellsworth 2013) explores this issue in depth and shows that injection wells have been directly linked to small magnitude earthquakes. In addition, (Frohlich 2012) shows data and analysis from a two-year survey comparing earthquake activity and injection-well locations in the Barnett Shale, Texas suggesting that due to the small magnitude of the earthquakes, they may be more common than what current data suggests.

8.3.1 Information Sources

Author	Title	Summarized Abstract
(Ellsworth 2013)	“Injection-induced earthquakes.”	This report: "Review[s] recent seismic activity that may be associated with industrial activity, with a focus on the disposal of wastewater by injection in deep wells; assess the scientific understanding of induced earthquakes; and discuss the key scientific challenges to be met for assessing this hazard."

(Frohlich 2012)	“Two-year survey comparing earthquake activity and injection-well locations in the Barnett Shale, Texas”	"Between November 2009 and September 2011, temporary seismographs deployed under the EarthScope USArray program were situated on a 70-km grid covering the Barnett Shale in Texas, recording data that allowed sensing and locating regional earthquakes with magnitudes 1.5 and larger. I analyzed these data and located 67 earthquakes, more than eight times as many as reported by the National Earthquake Information Center. All 24 of the most reliably located epicenters occurred in eight groups within 3.2 km of one or more injection wells. These included wells near Dallas-Fort Worth and Cleburne, Texas, where earthquakes near injection wells were reported by the media in 2008 and 2009, as well as wells in six other locations, including several where no earthquakes have been reported previously. This suggests injection-triggered earthquakes are more common than is generally recognized."
(Holland 2013)	“Earthquakes Triggered by Hydraulic Fracturing in South-Central Oklahoma”	"In January 2011, a sequence of earthquakes occurred in close proximity to a well, which was being hydraulically fractured in south-central Oklahoma. The hydraulic fracturing of the Picket Unit B Well 4-18 occurred from 16 January 2011 18:43 through 22 January 16:54 UTC. This vertical well penetrated into the mature Eola-Robberson oil field. Earthquakes were identified by cross correlating template waveforms from manually identified earthquakes and cross correlating these templates through the entire operation period of the Earthscope USArray Transportable Array (TA) station X34A. This produced a series of 116 earthquakes, which occurred from 17 January 2011 19:06 through 23 January 3:13 UTC with no other similar earthquakes identified at other times prior to or post-hydraulic fracturing. The identified earthquakes range in local magnitude (ML) from 0.6 to 2.9, with 16 earthquakes ML 2 or greater and a b-value of 0.98. There is a strong temporal correlation between hydraulic fracturing and earthquakes."

(Das and Zoback 2011)	"Long-period, long-duration seismic events during hydraulic fracture stimulation of a shale gas reservoir"	We report here a series of long-period and long-duration (LPLD) seismic events observed during hydraulic fracturing in a shale gas reservoir. These unusual events, 10-100 s in duration, are observed most clearly in the frequency band of 10-80 Hz and are remarkably similar in appearance to tectonic tremor sequences first observed in subduction zones. These complex but coherent wave trains have finite moveouts obtained from cross-correlation. The moveout direction of the events confirms that they originate in the reservoir from the area where the fracturing is going on. Clear P- and S-wave arrivals cannot be resolved within the LPLD episodes but, in some cases, small micro-earthquakes occur in the sequences. Whether these micro-earthquakes are causal or coincidental is not known. It has also been observed that in three contiguous frac-stages, all LPLD events appear to come from two distinct places along one of two hypothetical fracture planes.

8.3.2 Summary of Information

It is clear from the literature that injection of fluids into subsurface aquifers for the purposes of disposal can induce small earthquakes. This injection of fluids have in turn been linked to the massive volumes of produced water associated with hydraulic fracturing. However, the exact relationship has not been defined and is very location dependent. An important point to clarify is that the injection of water for disposal, and not necessarily for fracturing itself, has been linked to earthquakes.

(Ellsworth 2013) explains that the only requirements operators need to fulfill to conduct injection activities are: regulators approval, estimation of geologic fracture pressure, and generation of monthly reports regarding volume and pressure of water. This study concludes that this information is not sufficient to fully assess the risk from induced seismicity.

8.3.3 Conclusion and Regulations

This is an unsettled issue in the United States and an area of on-going research. Further work is needed to determine if current injection well standards and regulations are sufficient to ensure public safety.

We include relevant regulations from SB.4 below:

- **Relevant SB.4 Text 1785.1. Monitoring and Evaluation of Seismic Activity in the Vicinity of Hydraulic Fracturing.**

  (a) From commencement of hydraulic fracturing until 10 days after the end of hydraulic fracturing, the operator shall monitor the California Integrated Seismic Network for indication of an earthquake of magnitude 2.7 or greater occurring within a radius of five times the ADSA.
  (b) If an earthquake of magnitude 2.7 or greater is identified under subdivision (a), then the following requirements shall apply:

  (1) The operator shall immediately notify the Division and inform the Division when the earthquake occurred relative to the hydraulic fracturing operations.

  (2) The Division, in consultation with the operator and the California Geological Survey, will conduct an evaluation of the following:
  (A) Whether there is indication of a causal connection between the hydraulic fracturing and the earthquake;
  (B) Whether there is a pattern of seismic activity in the area that correlates with nearby hydraulic fracturing; and
  (C) Whether the mechanical integrity of any active well within the radius specified in subdivision (a) has been compromised.

  (3) No further hydraulic fracturing shall be done within the radius specified in subdivision (a) until the Division has completed the evaluation under subdivision (b)(2) and is satisfied that hydraulic fracturing within that radius does not create a heightened risk of seismic activity.

8.4 Water Reuse and Treatment

As stated before, Injection is not the only method of disposing produced water. Technologies exist to treat flow back water and make it usable for non oil and gas purposes. Currently in the U.S., there is a trend of reuse and treatment of produced water which is mainly led by the state of Pennsylvania due to its lack of available disposal wells.

8.4.1 Information Sources

The studies below, in conjunction with those listed in the produced water sections, outline the main issues regarding water re-use.

Author	Title	Summarized Abstract
(Rahm et al. 2013)	"Wastewater management and Marcellus Shale gas development: trends, drivers, and planning implications."	This study examines wastewater treatment in Pennsylvania and finds that: "From 2008 to 2011 wastewater reuse increased, POTW use decreased, and data tracking became more complete, while the average distance traveled by wastewater decreased by over 30%. Likely factors influencing these trends include state regulations and policies, along with low natural gas prices. Regional differences in wastewater management are influenced by industrial treatment capacity, as well as proximity to injection disposal capacity. Using lessons from the Marcellus Shale, we suggest that nations, states, and regulatory agencies facing new unconventional shale development recognize that pace and scale of well drilling leads to commensurate wastewater management challenges. We also suggest they implement wastewater reporting and tracking systems, articulate a policy for adapting management to evolving data and development patterns, assess local and regional wastewater treatment infrastructure in terms of capacity and capability, promote well-regulated on-site treatment technologies, and review and update wastewater management regulations and policies."
(Hayes et al. 2012)	"Barnett and Appalachian Shale water management and reuse technologies"	This report characterizes produced water, looks at re-use feasibility, alternative water sources, and various treatment options.
(Warner and Christie 2013)	"Impacts of shale gas wastewater disposal on water quality in western Pennsylvania"	"This study examined the water quality and isotopic compositions of discharged effluents, surface waters, and stream sediments associated with a treatment facility site in western Pennsylvania. The elevated levels of chloride and bromide, combined with the strontium, radium, oxygen, and hydrogen isotopic compositions of the effluents reflect the composition of Marcellus Shale produced waters. The discharge of the effluent from the treatment facility increased downstream concentrations of chloride and bromide above background levels. Barium and radium were substantially (>90%) reduced in the treated effluents compared to concentrations in Marcellus Shale produced waters. Nonetheless, 226Ra levels in stream sediments (544-8759 Bq/kg) at the point of discharge were approx. 200 times greater than upstream and background sediments (22-44 Bq/kg) and above radioactive waste disposal threshold regulations, posing potential environmental risks of radium bioaccumulation in localized areas of shale gas wastewater disposal."

8.4.2 Summary of Information

The many options to treat and reuse water outlined in the literature and each option comes with its own costs and physical limitations. While they are not widely implemented in the field, the literature suggests that one day re-use and treatment may become more common.

8.4.3 Analysis of Information

Treatment of produced water for re-use can be done through reverse osmosis or flash distillation. Reverse osmosis consists of forcing the produced water through membranes at high pressure. This process results in a stream of concentrated fluids (which still need to be disposed) and clean water. Flash distillation consists of boiling the water by lowering the pressure and increasing the temperature to also create a stream of concentrated fluids alongside clean water.

These methods although effective are quite expensive. (Acharya and Henderson 2010) shows how low-TDS flowback water (<45,000 mg/L) can be treated for either beneficial reuse or safe surface discharge through reverse osmosis treatments. Higher TDS levels (>45,000) require thermal distillation methods at a significantly higher cost. The study by (Hayes et al. 2012) conducts feasibility studies in the Marcellus and the Barnett plays and comes to the conclusion that treatment is feasible. However, depending on the quality of the produced water, the costs can range from $1 to $5 per bbl.

If the water quality is high-enough and TDS levels are low enough, the water can be reused in future hydraulic fracturing operations. This can be done through a mixture of treatment and dilution with fresh water. Water reuse lowers the water withdrawal burden on the local environment, reduces the required disposal volumes needed to dispose, and eliminates transport needs for produced water. However, as explained before, all water reuse requires some sort of treatment and thus potentially poses extra costs. Currently, due to the lack of injection wells in Pennsylvania, over 90% of produced water is reused for future hydraulic fracturing after initial basic treatment. This is estimated to cut down on water demand by 10% (Ma, Geza, and Xu 2014) (Rahm et al. 2013).

In the past, publicly owned treatment works (POTW) were the most used method of treatment in Pennsylvania. However this has fallen out of use given that these facilities were not able to fully treat the produced water. They became a vector for environmental contamination from the effluent. A study by Warner and Christie 2013 found that even though centralized treatment plants eliminate many of the constituents associated with produced water, the treated water still has high levels of bromide and chloride, plus radium levels 200 times larger than the upstream of the treatment plant were found. Moreover, this study found significant risks of long-term accumulation in the environment.

8.4.4 Conclusion of Water Reuse and Treatment

Other than for re-use for future hydraulic fracturing jobs, the current levels of full treatment for re-use are minimal (Ma, Geza, and Xu 2014). This is mainly because of the fact that disposal costs average $.25 per bbl compared to $1 to $5 for treatment (McCurdy 2011). However, with the increase in water scarcity, the increased feasibility of reusing water, public scrutiny, and water regulations, treatment and reuse is becoming a more viable option.

The relevant regulation from California's SB.4, API's water management guideline, and the text from the STRONGER guidelines are presented below.

- **Relevant SB.4 Text 1786. Storage and Handling of Well Stimulation Treatment Fluids and Wastes.**

  (a) Operators shall adhere to the following requirements for the storage and handling of well stimulation treatment fluid, additives, and produced water from a well that has had a well stimulation treatment:

  (1) Fluids shall be stored in compliance with the secondary containment requirements of Section 1773.1, except that secondary containment is not required under this section for production facilities that are in one location for less than 30 days. The operator's Spill Contingency Plan shall account for all production facilities outside of secondary containment and include specific steps to be taken and equipment available to address a spill outside of secondary containment.

  (2) Operators shall be in compliance with all applicable testing, inspection, and maintenance requirements for production facilities containing well stimulation treatment fluids.

  (3) Fluids shall be accounted for in the operator's Spill Contingency Plan.

  (4) Fluids shall be stored in containers and shall not be stored in sumps or pits.

  (5) In the event of an unauthorized release, the operator shall immediately implement the Spill Contingency Plan; notify the Regional Water Board and any other appropriate response entities for the location and the type of fluids involved, as required by all applicable federal, state, and local laws and regulations; and shall perform clean up and remediation of the area, and dispose of any cleanup or remediation waste, as required by all applicable federal, state, and local laws and regulations.

  (6) Within 5 days of the occurrence of an unauthorized release, the operator shall provide the Division a written report that includes:

  (A) A description of the activities leading up to the release;

  (B) The type and volumes of fluid released;

  (C) The cause(s) of release;

  (D) Action taken to stop, control, and respond to the release; and

(E) Steps taken and any changes in operational procedures implemented by the operator to prevent future releases.

(7) Operators shall conduct all activities that relate to storage and management of fluids in compliance with all applicable requirements of the Regional Water Board, the Department of Toxic Substances Control, the Air Resources Board, the Air Quality Management District or Air Pollution Control District, the Certified Unified Program Agency, and any other state or local agencies with jurisdiction over the location of the well stimulation activities.

(8) An operator who generates a waste, as defined in Health and Safety Code section 25124 and California Code of Regulations, title 22, section 66261.2, in the course of conducting well stimulation activities, including but not limited to well stimulation treatment fluid, additives, produced water from a well, solids separated from well stimulation treatment fluid, remediation wastes, or any other wastes generated from the processing, treatment or management of these wastes, shall determine if the waste is a hazardous waste by sampling and testing the waste according to the methods set forth in California Code of Regulations, title 22, division 4.5, chapter 11, article 3 (section 66261.20 et seq.), or according to an equivalent method approved by the Department of Toxic Substances Control pursuant to California Code of Regulations, title 22, section 66260.21, except where the operator has determined that the waste is excluded from regulation under California Code of Regulations, title 22, section 66261.4 or Health and Safety Code section 25143.2. Notwithstanding any other section in this article, wastes that are determined by the operator to be hazardous wastes shall be managed in compliance with all hazardous waste management requirements of the Department of Toxic Substances Control.

- **Relevant API Standard**
  - API Guidance Document HF2: Water Management Associated with Hydraulic Fracturing
- **Relevant STRONGER Guideline**
  9.3. Water and Waste Management Fundamental differences exist from state to state, and between regions within a state, in terms of geology and hydrology. The state should evaluate and address, where necessary, the availability of water for hydraulic fracturing in the context of all competing uses and potential environmental impacts resulting from the volume of water used for hydraulic fracturing. The use of alternative water sources, including recycled water, acid mine drainage and treated wastewater, should be encouraged.

  Waste associated with hydraulic fracturing should be managed consistent with Section 4.1.1. and Section 7 of the guidelines.

  States should encourage the efficient development of adequate capacity and infrastructure for the management of hydraulic fracturing fluids/wastes, including transportation (by pipeline or otherwise), recycling, treatment and disposal. State programs should address the integrity of pipelines for transporting and managing hydraulic fracturing fluids off the well pad.

8.5 Solid Waste

Most solid waste from oil and gas consists of drill cuttings and leftover proppant (frac sand) which are most often disposed in surface landfills. The total volume of waste varies greatly depending on the depth and geology of the plays. This section of the report explores solid waste in general drawing on existing literature and data gathered from the U.S. Radioactive materials will be discussed in section 8.6.

8.5.1 Information Sources

The following table aggregates the most relevant studies regarding issues of hydraulic fracturing solid waste:

Author	Title	Summarized Abstract
(Elshorbagy and Alkamali 2005)	"Solid waste generation from oil and gas industries in United Arab Emirates."	"This paper discusses the types, amounts, generation units, and the factors related to solid waste generation from a major oil and gas field in the United Arab Emirates (Asab Field). The generated amounts are calculated based on a 1-year data collection survey and using a database software specially developed and customized for the current study. The average annual amount of total solid waste generated in the studied field is estimated at 4061 t. Such amount is found equivalent to 650 kg/capita, 0.37 kg/barrel oil, and 1.6 kg/m3 of extracted gas. The average annual amount of hazardous solid waste is estimated at 55 t and most of which (73%) is found to be generated from gas extraction-related activities. The majority of other industrial non-hazardous solid waste is generated from oil production-related activities (41%), The present analysis does also provide the estimated generation amounts per waste type and class, amounts of combustible, recyclable, and compostable wastes, and the amounts dumped in uncontrolled way as well as disposed into special hazardous landfill facilities. The results should help the decision makers in evaluating the best alternatives available to manage the solid wastes generated from the oil and gas industries."
(Hammer and VanBriesen 2012)	*In Fracking's Wake: New Rules are Needed to Protect Our Health and Environment from Contaminated Wastewater*	"This report combines an evaluation of federal and state laws regulating fracking wastewater with a thorough review, compiled for NRDC by an independent scientist, of the health and environmental risks posed by this high-volume waste stream and the currently available treatment and disposal methods. It finds that the currently available options are inadequate to protect human health and the environment, but that stronger safeguards at the state and federal levels could better protect against the risks associated with this waste. The most significant of the policy changes needed now are (a) closing the loophole in federal law that exempts hazardous oil and gas waste from treatment, storage, and disposal requirements applicable to other hazardous waste, and (b) improving regulatory standards for wastewater treatment facilities and the level of treatment required before discharge to water bodies."
(PA DEP 2014a)	*PA DEP Oil & Gas - Statewide Data Downloads By Reporting Period*	"This data is provided by the Pennsylvania's Oil and Gas Act which requires unconventional well operators to submit production reports to the Department of Environmental Protection (DEP) biannually."

8.5.2 Summary of Information

Given the lack of information in regards to specific hydraulic fracturing solid waste. This report explores solid waste studies as they relate to oil and gas drilling in general. Most of the analysis comes from empirical evidence gathered in Pennsylvania.

8.5.3 Analysis of Information

The total volume of waste varies by well. A study by (NYSDEC 2011) gives an examples of vertical wells with a depth of 2,100 meters producing 120 cubic meters of cuttings and similar wells with horizontal sections producing 165 cubic meters. Figures 13 and 14 show the total waste generated in Pennsylvania for a 6 month period for drill cuttings and frac sand. This analysis gives a rough estimation of the volumes that need to be managed from each well. However this report does not speak to the potential hazard of those wastes as sufficient data is not available regarding this issue.

Figure 13: Total Drill Cuttings Generated in Pennsylvania (Tons), (PA DEP 2014a)

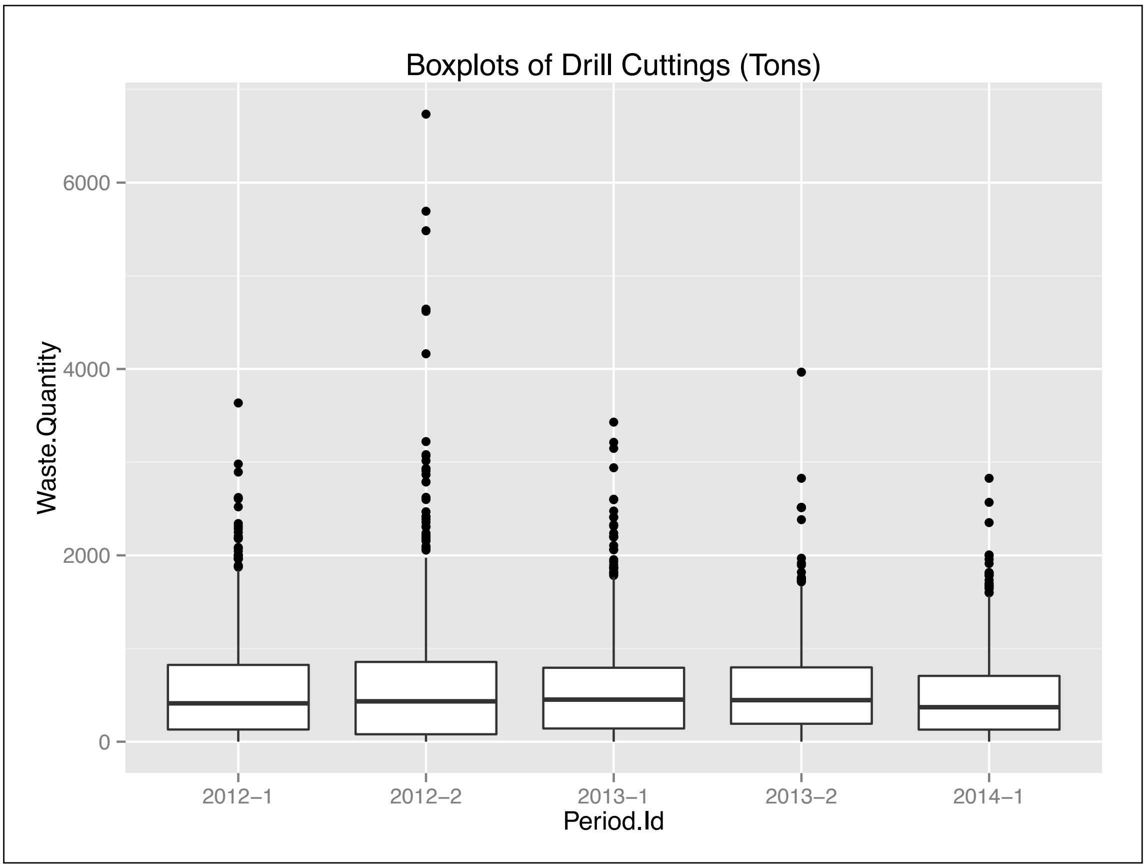


Figure 14: Total Frac Sand Generated in Pennsylvania (Tons), (PA DEP 2014a)

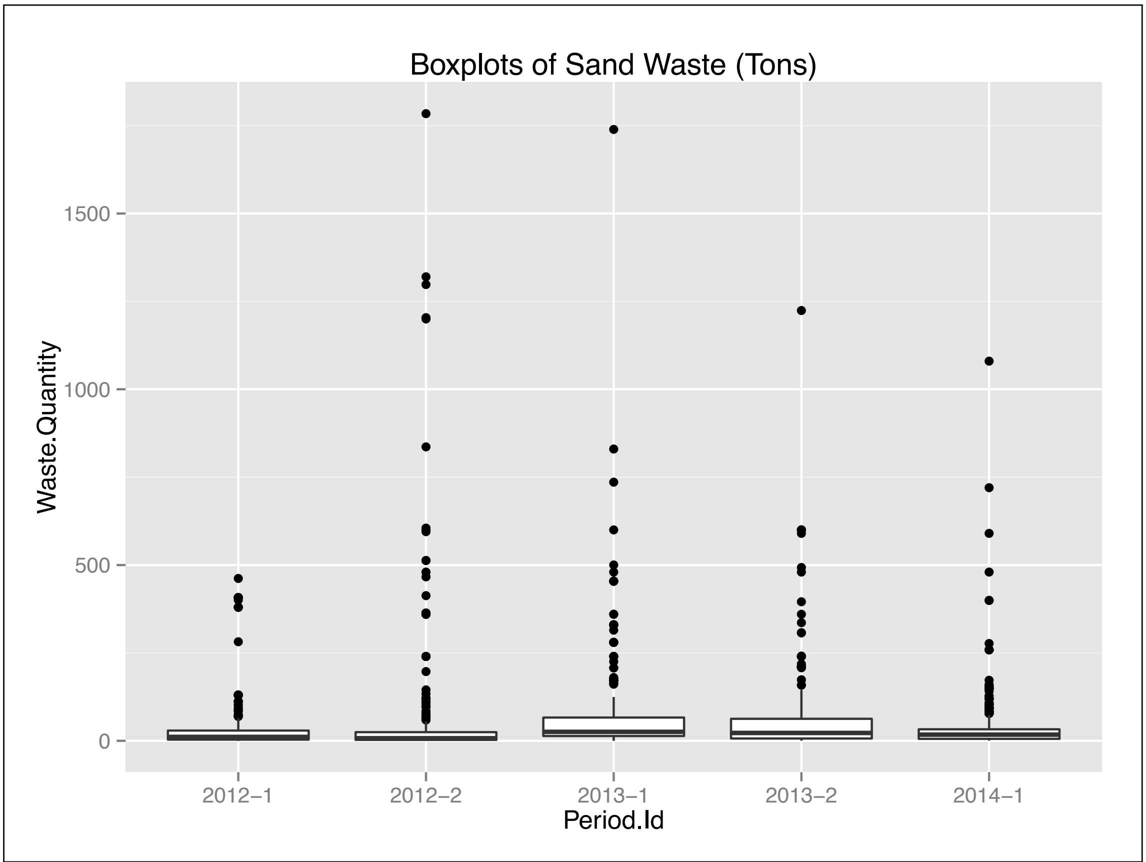


Table 32 shows the summary statistics per well over a 6-month period broken out by primary material (frac sand or drill cuttings). We can see that the vast majority of waste is drill cuttings and that the volumes vary greatly.

Table 32: Summary Waste Statistics broken out by Material (Tons), (PA DEP 2014a)

	Min	1st Quartile	Median	Mean	3rd Quartile	Max
Drill Cuttings	0.07	129.30	415.40	530.30	791.10	6735.00
Frac Sand	0.01	4.63	16.55	47.21	39.66	1784.00

Figure 15 aggregated the methods of solid waste disposal, by far the majority is disposed in a regular landfill. The data did not include NORM management. Summary statistics for the period from January 2012 to June 2014 are shown in table 33.

Figure 15: Solid Waste Disposal Methods in Pennsylvania 2012-2014, (PA DEP 2014a)

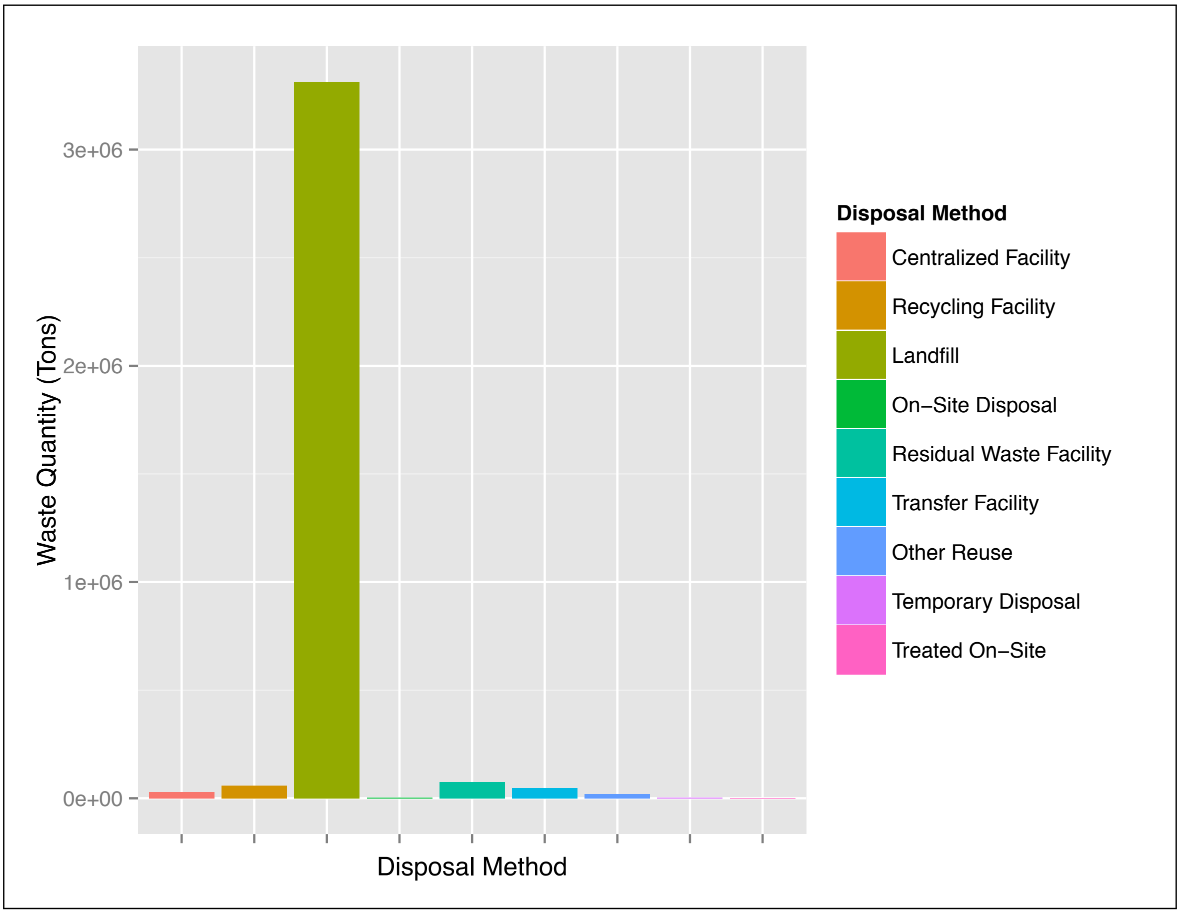


Table 33: Solid Waste Disposal Methods in Pennsylvania 2012-2014 (Tons), (PA DEP 2014a)

Disposal Method	Sum	Mean	Standard Deviation
Centralized Facility	28049.59	1402.48	1052.23
Recycling Facility	58688.37	279.47	533.86
Landfill	3312861.07	418.50	485.95
On-Site Disposal	4014.00	118.06	105.25
Residual Waste Facility	74992.60	438.55	470.48
Transfer Facility	47603.38	161.92	292.74
Other Reuse	18510.81	1234.05	666.84
Temporary Disposal	2953.82	44.75	74.20
Treated On-Site	6.98	0.41	0.35

8.5.4 Conclusions and Regulations

The majority of solid wastes related to hydraulic fracturing come from drill cuttings and sand. These wastes are disposed in traditional landfills. As they are legally exempt from hazardous waste laws, it is unknown what percentage of this waste is actually harmful. In regards to methods and laws, below are the relevant texts from SB.4, API waste management standards, and STRONGER guidelines.

- **Relevant SB.4 Text**

  1786. Storage and Handling of Well Stimulation Treatment Fluids and Wastes.
  ...
  (8) An operator who generates a waste, as defined in Health and Safety Code section 25124 and California Code of Regulations, title 22, section 66261.2, in the course of conducting well stimulation activities, including but not limited to well stimulation treatment fluid, additives, produced water from a well, solids separated from well stimulation treatment fluid, remediation wastes, or any other wastes generated from the processing, treatment or management of these wastes, shall determine if the waste is a hazardous waste by sampling and testing the waste according to the methods set forth in California Code of Regulations, title 22, division 4.5, chapter 11, article 3 (section 66261.20 et seq.), or according to an equivalent method approved by the Department of Toxic Substances Control pursuant to California Code of Regulations, title 22, section 66260.21, except where the operator has determined that the waste is excluded from regulation under California Code of Regulations, title 22, section 66261.4 or Health and Safety Code section 25143.2. Notwithstanding any other section in this article, wastes that are determined by the operator to be hazardous wastes shall be managed in compliance with all hazardous waste management requirements of the Department of Toxic Substances Control.

- **Relevant API Standard**

  API E5 -Environmental Guidance Document: Waste Management in Exploration and Production Operations

- **STRONGER Guideline**

  5.3. Waste Management Hierarchy
  As in any aspect of waste management, there are some general, sound practices that should be employed. These practices, which emphasize waste minimization, not only serve to protect human health and the environment, but also tend to protect waste generators from long-term liabilities associated with waste disposal. Additionally, waste minimization may reduce regulatory compliance concerns for E&P operators and result in cost savings. Generally, the choice of an E&P waste management option should be based upon the following hierarchy of preference:
  a. Source Reduction: Reduce the quantity and/or toxicity of the waste generated;

b. Recycling: Reuse or reclaim as much of the waste generated as possible, and whenever possible, combine hydrocarbons with crude oil, condensate, or natural gas liquids;

c. Treatment: Employ techniques to reduce the volume or the toxicity of waste that has been unavoidably generated.

d. Proper Disposal: Dispose of remaining wastes in ways that minimize adverse impacts to the environment and that protect human health.

8.6 Naturally Occurring Radioactive Materials (NORM)

Due to the history of their formation, the geologic formations that contain oil and gas deposits also contain naturally-occurring radionuclides, which are referred to as "NORM" (Naturally-Occurring Radioactive Materials), also known as TENORM (Technologically Enhanced Naturally-Occurring Radioactive Materials) as human activity increases its concentration. (Lopez 2013) states that radioactive wastes may be created through the process of hydraulic fracturing, including on pipe scale, filters, produced water, and water treatment equipment. The main constituents of this NORM are uranium, thorium, radium and their decay products (US EPA - Radiation Protection Division 2001).

8.6.1 Information Sources

The below studies are the most relevant regarding hydraulic fracturing and NORM. However, most relate solely to conventional oil and gas development.

Author	Title	Summarized Abstract
(Lopez 2013)	“Radiological Issues Associated With the Recent Boom in Oil and Gas Hydraulic Fracturing”	This article gives a brief overview of NORM issues across the world. With no strong conclusions, the report states that: "Industry experts, health physicists, regulators, and public communities must work together to understand and manage radiological issues to ensure reasonable and effective regulations protective of the public, environment, and worker safety implemented."
(US EPA - Radiation Protection Division 2001)	*Oil and Gas Production Wastes*	This page contains information about TENORM in oil and gas extraction wastes. It is a breif overview of EPAs management process and contains some sample data.

(Zielinski and Otton 1999)	"Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-field Equipment: An Issue for Energy Industry"	This report summarizes current understanding of the composition and mode of occurrence of oil-field NORM in the United States, briefly reviews the status of NORM regulations, and identifies some health and environmental issues associated with oil-field NORM.
(North Dakota Department of Health 2014)	*Technologically Enhanced Naturally Occurring Radioactive Material (TENORM) Disposal Limits In States Other Than North Dakota*	This report is a table of disposal limits for various states.
(Rowan et al. 2011)	"Radium content of oil-and gas-field produced waters in the Northern Appalachian basin (USA)-Summary and discussion of data"	This study collects data from the Marcellus Shale and finds: "The range of radium activities for samples from the Marcellus Shale (less than detection to 18,000 picocuries per liter (pCi/L)) overlaps the range for non-Marcellus reservoirs (less than detection to 6,700 pCi/L), and the median values are 2,460 pCi/L and 734 pCi/L, respectively. A positive correla- tion between the logs of TDS and radium activity can be demonstrated for the entire dataset, and controlling for this TDS dependence, Marcellus shale produced water samples contain statistically more radium than non-Marcellus samples. The radium isotopic ratio, Ra-228/Ra-226, in samples from the Marcellus Shale is generally less than 0.3, distinctly lower than the median values from other reservoirs. This ratio may serve as an indicator of the provenance or reservoir source of radium in samples of uncertain origin."
(Hamlat, Djeffal, and Kadi 2001)	"Assessment of radiation exposures from naturally occurring radioactive materials in the oil and gas industry"	This study collects NORM data from oilfields in Algeria. It also summarizes data from other countries.
(US EPA, OAR, ORIA 1997)	*Radiation and Health*	This report describes health effects of radiation and EPA's Radiation Protection Programs.
(Nussbaum 2014)	*Radioactive Waste Booms With Fracking as New Rules Mulled*	This news article describes the problem of 'frac socks' in North Dakota.

(Bhattacharyya 1998)	“Issues in the disposal of waste containing naturally occurring radioactive material”	This article considers a number of key issues in the disposal of waste containing enhanced levels of naturally occurring radioactive material (NORM), including gaseous, liquid and solid media. A brief review is made of sources of natural radioactivity in the biosphere and of anthropogenic enhancement of the concentration of NORM in the various media. The factors controlling the mobility of radionuclide activity in the environment are examined and disposal options are considered, comparison also being made with disposal of nuclear fuel cycle materials, in particular the tailings of uranium mining. Current and proposed disposal and policies for NORM are cited, reference being made to experiences in a number of countries.

8.6.2 Summary of Information

In terms of actual data, (Rowan et al. 2011) and (Hamlat, Djeffal, and Kadi 2001) are good sources as they analyze radiation levels in a multitude of oil and gas fields. There is still debate on what constitutes "safe" levels of low-level radiation which may be the reason for the vast disparity in regulations (US EPA, OAR, ORIA 1997).

What is clear from the above studies though, is that this area of research lacks hard data and is not sufficiently assessed in terms of hydraulic fracturing. Much information can be drawn from literature from conventional oil and gas development, however as shale oil and gas development interacts much closer to the source rock itself, it is unknown whether the same lessons could apply.

8.6.3 Analysis of Information

Uranium, thorium, radium and their decay products build up on pipes and can be contained in sludge and other wastes. In the oil and gas industry, the levels vary highly by both location as shown in figure 16 and by overall radioactivity as shown in figure 17. Both of these graphs were produced by the United States Geological Survey (Zielinski and Otton 1999).

Figure 16: US Radiation Levels, (Zielinski and Otton 1999)

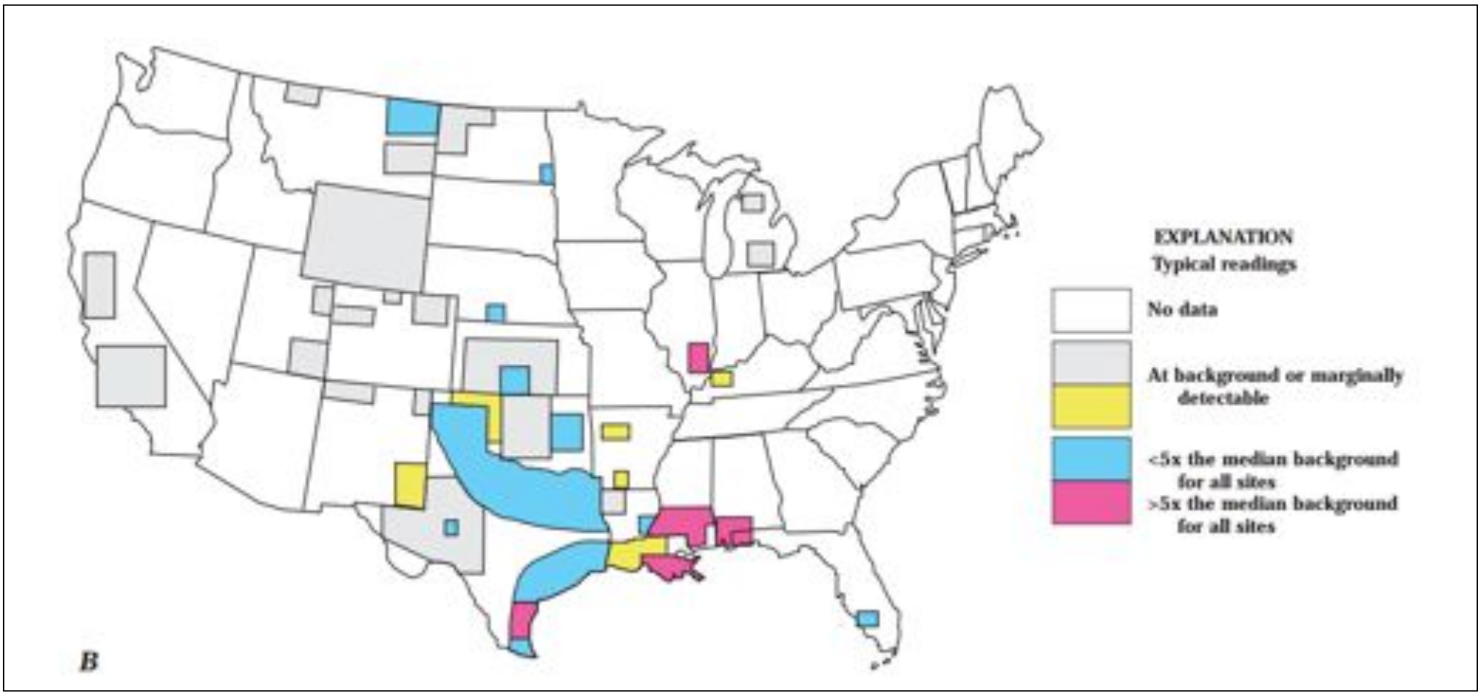


Figure 17: Radium in Various Plays (Zielinski and Otton 1999)

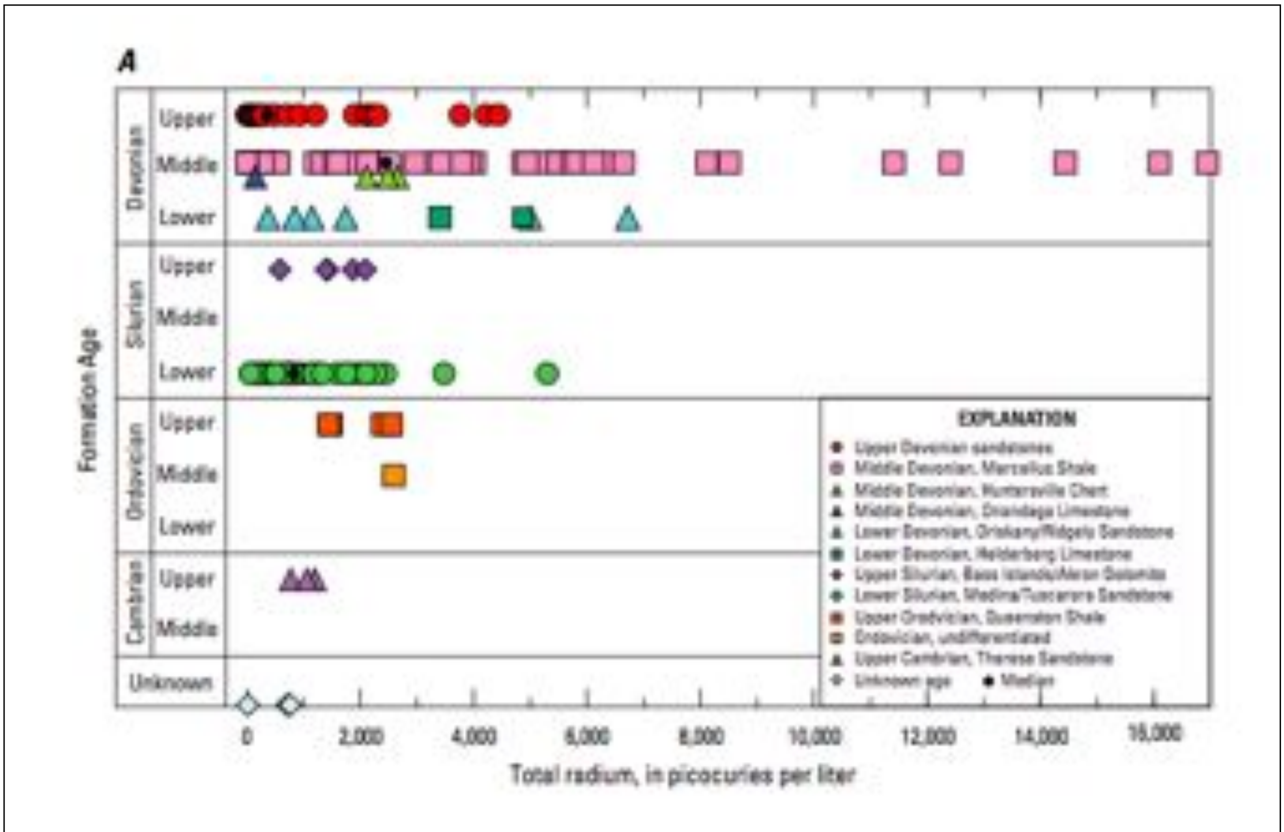


Table 35 shows the range of radioactivity found on infrastructure in plays with NORM. Similarly, 36 uses another unit of measurement. It is clear here that levels vary greatly but can potentially exceed safe limits.

Table 35: TENORM Observations, (US EPA - Radiation Protection Division 2001)

Range of Radioactivity Concentrations-Radium 226			
Source	Low	Average	High
Produced Water	0.1 pCi/l	-	9000 pCi/l
Pipe/Tank Scale	<0.25 pCi/g	<200 pCi/g	>100000 pCi/g

Table 36: TENORM Observations, (Lopez 2013)

Source	Low	High
Produced Water [Bq/liter]	.00370	333
Pipe/Tank Scale [Bq/g]	<.00925	3700

However, the limits of hazardous NORM vary by state. Many regulatory agencies have jurisdiction including health departments, oil and gas commissions, and departments of environmental protection. Some states even lack a policy regarding NORM altogether (Lopez 2013). To illustrate the vast differences in safe limits (North Dakota Department of Health 2014) compiled a table of various radiation disposal limits for U.S. states. These are shown in 37. Any wastes above this limit must be handled and disposed of according to radioactive waste regulations.

Table 37: Legal Radiation Limits, (North Dakota Department of Health 2014)

State	Disposal Limit (picocuries per gram)	Radionuclide	Type of Limit
California	1800	total picocuries/gram	landfill permit
Colorado	2000	total picocuries/gram	landfill permit
Idaho	1500	Ra-226 and Ra-228	landfill permit
Illinois	200	Ra-226	state rule for drinking water treatment sludge
Louisiana	30	Ra-226	state rule
Michigan	50	Ra-226 and Ra-228	state rule
Minnesota	30	Ra-226	state rule for drinking water treatment sludge
Mississippi	30	Ra-226 and Ra-228	state rule
Montana	30	Ra-226 and Ra-228	state policy
New Mexico	30	Ra-226 or Ra-228	state rule - landspreading
Texas	30	Ra-226 or Ra-228	state rule - landspreading
Utah	10000	Ra-226 and Ra-228	landfill permit
Washington	10000	Ra-226 and Ra-228	landfill permit
Wyoming	50	Ra-226 and Ra-228	state policy

As it is clear, there is no consensus on regulatory limits. However currently the NORM that does exceed limits is disposed of in injection wells, well bores during plugging, or sent to a landfill licensed to accept NORM (US EPA - Radiation Protection Division 2001).

What is troubling is that there is evidence of a lack of capacity to dispose of the waste. In North Dakota filters known as "frac socks" have overwhelmed disposal facilities. One estimate fixes the amount of waste at over 27 tons a day. In addition there have been numerous incidents of illegal waste dumping (Nussbaum 2014).

8.6.4 Conclusions and Regulations

Despite the variation at state level regulation, radiation is a long-term problem. If development were to occur in any area with naturally high NORM levels, adequate disposal and management capacity must be in place. (Bhattacharyya 1998) looks at methods of disposing waste containing NORM and is a good starting reference.

Below are state regulations from Texas and Pennsylvania, both states have large scale oil and gas development in areas that contain significant NORM. Also, this report adds references to relevant API standards and STRONGER guidelines.

- **Relevant State Report - Pennsylvania:** PA DEP (2015). *Technologically Enhanced Naturally Occuring Radioactive Materials (TENORM) Study Report*. Tech. rep. URL: `http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-105822/PA-DEP-TENORM-Study\_Report\_Rev.\_0\_01-15-2015.pdf`

  Synopsis
  In 2013, the Pennsylvania Department of Environmental Protection (DEP) initiated a study to collect data relating to technologically enhanced naturally occurring radioactive material (TENORM) associated with oil and gas (O&G) operations in Pennsylvania. This study included the assessment of potential worker and public radiation exposure, TENORM disposal, and other possible environmental impacts. The study encompassed radiological surveys at well sites, wastewater treatment plants, landfills, gas distribution and end use, and O&G brine-treated roads. The media sampled included solids, liquids, natural gas, ambient air, and surface radioactivity.

  The observations and recommendations for future actions based on this peer-reviewed study are:
  1. There is little potential for additional radon exposure to the public due to the use of natural gas extracted from geologic formations located in Pennsylvania.
  2. There is little or limited potential for radiation exposure to workers and the public from the development, completion, production, transmission, processing, storage, and end use of natural gas. There are, however, potential radiological environmental impacts from O&G fluids if spilled. Radium should be added to the Pennsylvania spill protocol to ensure cleanups are adequately characterized. There are also site-specific circumstances and situations where the use of personal protective equipment by workers or other controls should be evaluated.
  3. There is little potential for radiation exposure to workers and the public at facilities that treat O&G wastes. However, there are potential radiological environmental impacts that should be studied at all facilities in Pennsylvania that treat O&G wastes to determine if any areas require remediation. If elevated radiological impacts are found, the development of radiological discharge limitations and spill policies should be considered.
  4. There is little potential for radiation exposure to workers and the public from landfills receiving waste from the O&G industry. However, filter cake from facilities treating O&G wastes are a

potential radiological environmental impact if spilled, and there is also a potential long-term disposal issue. TENORM disposal protocols should be reviewed to ensure the safety of long-term disposal of waste containing TENORM.
5. While limited potential was found for radiation exposure to recreationists using roads treated with brine from conventional natural gas wells, further study of radiological environmental impacts from the use of brine from the O&G industry for dust suppression and road stabilization should be conducted.

- **Relevant State Regulation - Texas: 16 Texas Administrative Code, Title 16, Part 1, Chapter 4, Subchapter F, §4.601 - 4.632**

  The following words and terms, when used in this subchapter, shall have the following meanings, unless the context clearly indicates otherwise.

  (1) Background radiation–Radiation at the ground surface from:

  (A) cosmic sources;

  (B) non-technologically enhanced naturally occurring radioactive material, including radon, except as a decay product of source or special nuclear material; or

  (C) global fallout as it exists in the environment from the testing of nuclear explosive devices. "Background radiation" does not include sources of radiation from radioactive materials regulated by the TDH.
  (2) Commission–The Railroad Commission of Texas or its designee.
  (3) Disposal–Engaging in the act of discharging, depositing, injecting, dumping, spilling, leaking, or placing of any oil and gas NORM waste into or on any land or water, or causing or allowing any such act, so that such waste, or any constituent thereof, may enter the environment or be emitted into the air or discharged into any waters, including subsurface waters. For purposes of this subchapter, disposal of oil and gas NORM waste includes its management at the site (e.g., lease, unit, or facility) where disposal will occur when undertaken for the explicit purpose of facilitating disposal at that site. The term does not include decontamination activities, except for in-place mixing of oil and gas NORM waste to remedy historical contamination of the land surface and decontamination of equipment and facilities that become contaminated solely through disposal operations. In addition, the term does not include activities, including processing or treatment, that occur at a location other than the disposal site.
  (4) Equipment–Oil and gas equipment used for production or disposal, including but not limited to pipes (tubulars), tanks, vessels, pumps, valves, flow lines, and connectors such as tees and elbows, provided that such equipment is or has been in contact with oil and gas waste or produced fluids or substances.
  (5) Microroentgens per hour (μ R/hr)–A measurement of exposure from x-ray and gamma ray radiation in air.
  (6) NORM–Naturally occurring radioactive material.
  (7) NORM-contaminated equipment–Equipment that, at any accessible point, exhibits a minimum radiation exposure level greater than 50 μR/hr including background radiation level.
  (8) Oil and gas waste–Oil and gas waste as defined in Âğ3.8 of this title (relating to Water Protection).

(9) Oil and gas NORM waste–Any solid, liquid, or gaseous material or combination of materials (excluding source material, special nuclear material, and by-product material) that:

(A) in its natural physical state spontaneously emits radiation;

(B) is discarded or unwanted;

(C) constitutes, is contained in, or has contaminated oil and gas waste; and

(D) prior to treatment or processing that reduces the radioactivity concentration, exceeds exemption criteria specified in 25 TAC §289.259(d) (relating to Licensing of Naturally Occurring Radioactive Material (NORM)).
- (10) Person–A natural person, corporation, organization, government or governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.
- (11) Picocuries per gram (pCi/g)–A measure of the radioactivity in one gram of a material. One picocurie is that quantity of radionuclide(s) that decays at the rate of 3.7 x 10-2 disintegrations per second.
- (12) Radiation survey instrument–An instrument used to detect and measure radiation exposure levels from 1 μR/hr through at least 500 μR/hr.

- **Relevant API Standard:**
  -Bull E2-Management of Naturally Occurring Radioactive Materials (NORM) in Oil and Gas Production
  -Publ 7102-Methods for Measuring Naturally Occurring Radioactive Materials (NORM) in Petroleum Production Equipment.
- **Relevant STRONGER Guideline:**

  7.2. General
  States should adopt an oil field NORM regulatory program that addresses identification, use, possession, transport, storage, transfer, decontamination, and disposal to protect human health and the environment. States may choose not to adopt such a program if they find, based on field monitoring data and other scientific information, that no NORM is present in oil and gas operations in the State, or that the levels of NORM present in oil and gas operations in the State do not present such a risk to human health or the environment to warrant a regulatory program. States that make such a finding should periodically reevaluate the basis for the determinations.

  If a state determines that a regulatory program is necessary, it should tailor its program to NORM occurrence in the oil and gas E&P industry and an assessment of risks to human health and the environment. The program should include the elements listed in Section 7.3. Oil-field NORM should be managed in accordance with the pollution prevention and waste management hierarchy provisions of these guidelines. In addition, the other sections of these guidelines apply, where applicable, to NORM as a constituent of E&P waste.

9 People and Communities

All of the benefits of hydraulic fracturing must be weighed against the harms in causes to people and communities; this is the ultimate cost-benefit calculation needed in deciding appropriate policies. The people exposed to the harms of hydraulic fracturing, listed from most to least immediate, include: oil and gas workers, community members who live near wells, people who use aquifers for drinking and agriculture, communities within range of ozone and air impacts, and finally the global population as everyone is subject to the consequences of climate change. This report has touched on some of the effects in the above sections, but will reference resources and studies relevant to each of the above issues.

9.1 Worker Safety

While operational health and safety is out of the scope of this report. It needs to be kept in mind and should not be ignored in any analysis. Regulations regarding oil and gas worker health and safety can be found from Occupational Safety and Health Administration which runs an online database to highlight some (but not all) of the hazards involved with oil and gas development. The guide can be found here: `https://www.osha.gov/SLTC/etools/oilandgas/index.html`

9.2 Local Community Impacts

The communities section collects sources that look at community impacts unrelated to health such as day-to-day life, public perception, and employment and income. Oil and gas development in communities is a mixed-blessing. It can provide much needed employment and tax income for communities, however it also can strain resources and increase crime. In this regard, it is important to note that public engagement is crucial given that it promotes better decision-making, stimulates community trust, and ultimately reduces associated negative impacts as the ones presented in this section, all of this while also deterring negligent practices through accountability.

9.2.1 Information Sources

(Haggerty et al. 2014)	"Long-term effects of income specialization in oil and gas extraction: The U.S. West, 1980-2011"	This study looks at the long-term effects of the boom and bust cycle. "The purpose of the study is to evaluate the relationships between oil and natural gas specialization and socioeconomic well-being during the period 1980 to 2011 in a large sample of counties within the six major oil- and gas-producing states in the interior U.S. West: Colorado, Montana, New Mexico, North Dakota, Utah, and Wyoming. ... Our findings contribute to a broader public dialogue about the consequences of resource specialization involving oil and natural gas and call into question the assumption that long-term oil and gas development confers economic advantages upon host communities."
(Boxall, Chan, and McMillan 2005)	"The impact of oil and natural gas facilities on rural residential property values: a spatial hedonic analysis"	This paper examines the impact of oil and gas facilities on rural residential property values using data from Central Alberta, Canada." The influences are evaluated using two groups of variables characterizing hazard effects and amenity [structure] effects. A spatial error model was employed to capture the spatial dependence between neighbouring properties. The results show that property values are negatively correlated with the number of sour gas wells and flaring oil batteries within 4km of the property. Indices reflecting health hazards associated with potential rates of H2S release (based on information from Emergency Response Plans and Zones) also have a significant negative association with property prices. The findings suggest that oil and sour gas facilities located within 4km of rural residential properties significantly affect their sale price."
(Measham and Fleming 2014)	"Impacts of unconventional gas development on rural community decline"	This paper looks at coal seam gas in Australia and finds: "The extensive spatial footprint of unconventional gas and increased female rural youth populations indicate a diversion from traditional boomtown social impacts observed in previous energy booms. Taken together, the results show signs of mitigating and reversing rural community decline."
(Weber 2012)	"The effects of a natural gas boom on employment and income in Colorado, Texas, and Wyoming"	This study "find[s] that a large increase in the value of gas production caused modest increases in employment, wage and salary income, and median household income. The results suggest that each million dollars in gas production created 2.35 jobs in the county of production, which led to an annualized increase in employment that was 1.5% of the pre-boom level for the average gas boom county. Comparisons show that ex-ante estimates of the number of jobs created by developing the Fayetteville and Marcellus shale gas formations may have been too large."

(Munasib and Rickman 2015)	“Regional economic impacts of the shale gas and tight oil boom: A synthetic control analysis”	"[T]his paper examines the net economic impacts of oil and gas production from shale formations for key shale oil and gas producing areas in Arkansas, North Dakota and Pennsylvania. The synthetic control method (Abadie and Gardeazabal, 2003; Abadie et al., 2010) is used to establish a baseline projection for the local economies in the absence of increased energy development, allowing for estimation of the net regional economic effects of increased shale oil and gas production."
(Muehlenbachs and Krupnick 2013)	“Shale Gas Development Linked to Traffic Accidents in Pennsylvania”	This report "links shale gas well development activities to traffic-related accidents in Pennsylvania. They used data on accidents from the Crash Reporting System maintained by the Pennsylva- nia Department of Transportation, which provides detailed information, such as the types of vehicles involved in an accident, the exact location and time of the accident, and the severity of the accident."
(Graham et al. 2015)	“Increased traffic accident rates associated with shale gas drilling in Pennsylvania”	This report "examined the association between shale gas drilling and motor vehicle accident rates in Pennsylvania... Vehicle accidents have measurably increased in conjunction with shale gas drilling."
(Abramzon and Samaras 2014)	“Estimating the consumptive use costs of shale natural gas extraction on Pennsylvania roadways”	"This technical note, provides a first-order an estimate of roadway consumptive use costs of additional heavy truck traffic on Pennsylvania state-maintained roadways from Marcellus Shale natural gas development in 201, estimated at 1 about \$13,000-\$23,000 per well for all state roadway types, or \$5,000-\$10,000 per well if state roads with the lowest traffic volumes are excluded. This initial estimate of costs, is based on data on the distribution of well activity and roadway type in Pennsylvania, estimates for the number of heavy truck trips to construct and operate a single well, the corresponding equivalent single-axle loadings, and estimates of roadway life and reconstruction costs by roadway maintenance class in Pennsylvania."

9.2.2 Summary of Information

The impacts on social structures are mixed in the literature and both benefits and as well as real social harms such as traffic fatalities, crime, noise are identified.

9.2.3 Analysis of Information

One long-term study that has investigated the effect of the oil and gas industry on rural development is a study by (Haggerty et al. 2014) that came to the conclusion that counties dependent on oil and gas development were demonstrably worse-off than counties that weren’t. There are significant caveats to this study and it doesn’t fully explore the counter-factual.

(Boxall, Chan, and McMillan 2005) examines the impact of oil and gas facilities on rural residential property values using data from Central Alberta, Canada. (Measham and Fleming 2014) looks at coal seam gas's impact on rural communities in Australia and suggests some reversal of rural decline.(Weber 2012) and (Munasib and Rickman 2015) look at employment, income, and economic impact in communities and suggest that the positive effects are not as large as in input-out models.
The visual and audible impacts of oil and gas are some of the largest complaints that communities have regarding development. As with most impacts regarding shale development, it varies depending on local conditions. However table 39 from the US Bureau of Reclamation (USBR) give the relative impacts of different noise sources including oil and gas.

Table 39: USBR Noise, (US Bureau of Reclamation 2008)

Activity	Range	Timing Pattern
Site construction and rehabilitation (earth moving and agricultural equipment)	93 -108	Intermittent-Fluctuating sound levels-Typically day operations only
Oil/gas drilling/workover	100 - 130	Intermittent-Fluctuating sound levels-24 hour/day operations-1 week to several months duration
Oil/gas fracturing operation	100 - 145	Intermittent-Fluctuating sound levels-Venting/flaring operations are loudest and most continuous-but last only 1-2 days-24 hour/day operations-1 -2 weeks duration
Oil/gas operations	62-87	Long term-continuous sound levels-24 hours/day-7 days/week-year round operations
Natural gas compressors	62-87	Long term-continuous sound levels-24 hours/day- 7 days/week- year round operations-Low pitched sound
Highway traffic	80-100	Intermittent-Fluctuating sound levels-Generally heavier use during daylight hours
Developed recreational areas (Ldn)	50 - 65	Intermittent-Fluctuating sound levels-Generally more activity during summer daylight hours
Motor boating (including jet skis)	70 - 115	Intermittent- Fluctuating sound levels-Generally heavier use during daylight hours

In addition, many shale developments experience significant increase the traffic and the consequences thereof. Table 40 shows the estimated number of number of truck trips per well needed (NYSDEC 2011). This increases the risk of traffic accidents, local air pollution emissions, and also increases the community burden by wearing out roads. A study by (Muehlenbachs and Krupnick 2013) shows that for every well drilled in Pennsylvania, the number of fatal accidents in that county increases by 0.6 percent and the number of heavy-truck accidents increased by 2 percent. Reflecting this, (Graham et al. 2015) also comes to the conclusion that traffic accidents are heavier in counties with oil and gas development.

Table 40: Truck Trips per Well, (NYSDEC 2011)

	Horizontal Well with High-Volume Hydraulic Fracturing		Vertical Well	
	Heavy Truck	Light Truck	Heavy Truck	Light Truck
Light-duty trips	831	795	507	507
Heavy-duty trips	1,148	625	389	310
Combined Total	1,975	1,420	905	817
Total Vehicle Trips	3,950	2,840	1,810	1,634

(Abramzon and Samaras 2014) estimates the total monetary damage done to roads. Table 41 replicates some of the conclusions. Note that the letters A through E designate the type of road from interstate (A) to local roads (E).

Table 41: Cost Estimates to Roads, (Abramzon and Samaras 2014)

Truck trip assumptions	Road class	A	B	C	D	E	Total
Low truck trip range	Consumptive roadway use per well (%)	0.0001	0.0001	0.0015	0.0036	0.0077	-
	Damage costs per lane mile for each well	$2	$3	$40	$92	$180	$315
High truck trip range	Consumptive roadway use per well (%)	0.0001	0.0002	0.0027	0.0066	0.0142	-
	Damage costs per lane mile for each well	$3	$5	$72	$168	$331	$580

(James and Smith 2014) shows that: "..shale-rich counties experienced faster growth in rates of both property and violent crimes including rape, assault, murder, robbery, burglary, larceny and grand theft auto." The study stresses that policymakers should be prepared ahead of time in certain boom-town communities.

9.2.4 Conclusions

Good public policy requires a holistic incorporation of all the negative externalities. The above impacts on communities economies and social services show that the social effects of oil and gas drilling extend further than the direct environmental impacts and should be taken into account in planning.

10 Risk Analyses

The overall risk related to hydraulic fracturing depends on the likelihood of harm coupled with the magnitude of that harm. Several studies attempt to quantify this risk. However, it is very difficult to predict all possible situations and any harm done would require complete information to assess total potential damage. In reality, total potential damage is a function of not only probabilistic elements, but operators, local conditions, regulators, and a myriad list of other factors. Consideration of hazards and risks associated with the management of specific chemical additives and waste is site-specific, as such, it is beyond the scope of this risk assessment.

10.1 Health

This report will first focus on health risk assessments, the literature of which is outlined below. Due to the complicated and long-term nature of health research much of the literature comes to the conclusion that "more research is needed".

10.1.1 Information Sources

(Bloomdahl et al. 2014)	"Assessing worker exposure to inhaled volatile organic compounds from Marcellus Shale flowback pits"	"The objective of this study was to assess this worker exposure and the resulting health risks for 12 VOCs present in flowback water stored in such an open reservoir on a drilling site... A literature review was performed to determine VOC health effects, exposure limits, and worker protection methods. Neither model demonstrated an increased risk of adverse effects due to subchronic exposure at the 2.5 percentile and mean concentration values for the 12 VOCs as indicated by hazard quotients, hazard indices, or excess lifetime cancer risks; however, 97.5 percentile hazard indices approached 1 in one model and did demonstrate unacceptable risks in the evaluation of limitations. Either model may apply to worker health assessment depending upon industry practice; however, differing weather conditions, industry practice, and the small number of VOCs evaluated necessitate further research regarding worker risks and health effects.

(Colborn et al. 2011)	“Natural Gas Operations from a Public Health Perspective”	This study looked at chemicals used within the process and found a "list of 944 products containing 632 chemicals used during natural gas operations was compiled. Literature searches were conducted to determine potential health effects of the 353 chemicals identified by Chemical Abstract Service (CAS) numbers. More than 75% of the chemicals could affect the skin, eyes, and other sensory organs, and the respiratory and gastrointestinal systems. Approximately 40-50% could affect the brain/nervous system, immune and cardiovascular systems, and the kidneys; 37% could affect the endocrine system; and 25% could cause cancer and mutations. These results indicate that many chemicals used during the fracturing and drilling stages of gas operations may have long-term health effects that are not immediately expressed."
(Werner et al. 2015)	“Environmental health impacts of unconventional natural gas development: A review of the current strength of evidence”	"This paper is a review of the strength of evidence in scientific reporting of environmental hazards from UNGD activities associated with adverse human health outcomes....Current scientific evidence for UNGD that demonstrates associations between adverse health outcomes directly with environmental health hazards resulting from UNGD activities generally lacks methodological rigour. Importantly, however, there is also no evidence to rule out such health impacts. While the current evidence in the scientific research reporting leaves questions unanswered about the actual environmental health impacts, public health concerns remain intense. This is a clear gap in the scientific knowledge that requires urgent attention."
(Finkel and Hays 2013)	“The implications of unconventional drilling for natural gas: a global public health concern.”	This report finds that: "Given that no sound epidemiologic study has been done to assess the extent of exposure-related adverse health effects among populations living in areas where natural gas extraction is going on, it is imperative that research be conducted to quantify the potential risks to the environment and to human health not just in the short-term, but over a longer time period since many diseases (i.e., cancers) appear years after exposure. It should not be concluded that an absence of data implies that no harm is being done."

(McKenzie et al. 2012)	"Human health risk assessment of air emissions from development of unconventional natural gas resources."	This study "estimated health risks for exposures to air emissions from a NGD project in Garfield County, Colorado with the objective of supporting risk prevention recommendations in a health impact assessment (HIA)." and found that "Residents living ≤ .5 mile from wells are at greater risk for health effects from NGD than are residents living > .5 mile from wells. Subchronic exposures to air pollutants during well completion activities present the greatest potential for health effects. The subchronic non-cancer hazard index (HI) of 5 for residents ≤ .5 mile from wells was driven primarily by exposure to trimethylbenzenes, xylenes, and aliphatic hydrocarbons. Chronic HIs were 1 and 0.4. for residents ≤ .5 mile from wells and > .5 mile from wells, respectively. Cumulative cancer risks were 10 in a million and 6 in a million for residents living ≤ .5 mile and > .5 mile from wells, respectively, with benzene as the major contributor to the risk."
(McKenzie et al. 2014)	"Birth outcomes and maternal residential proximity to natural gas development in rural Colorado."	This study "examined associations between maternal residential proximity to NGD and birth outcomes in a retrospective cohort study of 124,842 births between 1996 and 2009 in rural Colorado." The results: "In this large cohort, we observed an association between density and proximity of natural gas wells within a 10-mile radius of maternal residence and prevalence of CHDs [congenital heart defects] and possibly NTDs [neural tube defects]. Greater specificity in exposure estimates is needed to further explore these associations.

(Jenner and Lamadrid 2013)	“Shale gas vs. coal: Policy implications from environmental impact comparisons of shale gas, conventional gas, and coal on air, water, and land in the United States”	"The aim of this paper is to examine the major environmental impacts of shale gas, conventional gas and coal on air, water, and land in the United States. These factors decisively affect the quality of life (public health and safety) as well as local and global environmental protection. Comparing various lifecycle assessments, this paper will suggest that a shift from coal to shale gas would benefit public health, the safety of workers, local environmental protection, water consumption, and the land surface. Most likely, shale gas also comes with a smaller GHG footprint than coal. However, shale gas extraction can affect water safety. This paper also discusses related aspects that exemplify how shale gas can be more beneficial in the short and long term. First, there are technical solutions readily available to fix the most crucial problems of shale gas extraction, such as methane leakages and other geo-hazards. Second, shale gas is best equipped to smoothen the transition to an age of renewable energy. Finally, this paper will recommend hybrid policy [both self-imposed and legal] regulations."
(Eaton 2013)	“Science-based decision-making on complex issues: Marcellus shale gas hydrofracking and New York City water supply.”	This report "review[s] the scientific and technical aspects in combination with global climate change and other critical issues in energy tradeoffs, economics and political regulation to evaluate the major liabilities and benefits. Although potential benefits of Marcellus natural gas exploitation are large for transition to a clean energy economy, at present the regulatory framework in New York State is inadequate to prevent potentially irreversible threats to the local environment and New York City water supply. Major investments in state and federal regulatory enforcement will be required to avoid these environmental consequences, and a ban on drilling within the NYC water supply watersheds is appropriate, even if more highly regulated Marcellus gas production is eventually permitted elsewhere in New York State."

(Oswald and E. 2012)	*Impacts of Gas Drilling on Human and Animal Health*	With a focus potential impacts, this study looks at community health problems in regards to shale development and comes to the conclusion that: "Documentation of cases in six states strongly implicates exposure to gas drilling operations in serious health effects on humans, companion animals, livestock, horses, and wildlife. Although the lack of complete testing of water, air, soil and animal tissues hampers thorough analysis of the connection between gas drilling and health, policy changes could assist in the collection of more complete data sets and also partially mitigate the risk to humans and animals. Without complete studies, given the many apparent adverse impacts on human and animal health, a ban on shale gas drilling is essential for the pro tection of public health"
(New York State Department of Health 2014)	*A Public Health Review of High Volume Hydraulic Fracturing for Shale Gas Development*	This New York State Deparment of Health report: "(i) reviewed and evaluated scientific literature to determine whether the current scientific research is sufficient to inform questions regarding public health impacts of HVHF; (ii) sought input from three outside public health expert consultants; (iii) engaged in field visits and discussions with health and environmental authorities in states with HVHF activity; and (iv) communicated with multiple local, state, federal, international, academic, environmental, and public health stakeholders. The evaluation considered the available information on potential pathways that connect HVHF activities and environmental impacts to human exposure and the risk for adverse public health impacts."

(Vengosh et al. 2014)	"A critical review of the risks to water resources from unconventional shale gas development and hydraulic fracturing in the United States."	The rapid rise of shale gas development through horizontal drilling and high volume hydraulic fracturing has expanded the extraction of hydrocarbon resources in the U.S. The rise of shale gas development has triggered an intense public debate regarding the potential environmental and human health effects from hydraulic fracturing. This paper provides a critical review of the potential risks that shale gas operations pose to water resources, with an emphasis on case studies mostly from the U.S. Four potential risks for water resources are identified: (1) the contamination of shallow aquifers with fugitive hydrocarbon gases (i.e., stray gas contamination), which can also potentially lead to the salinization of shallow groundwater through leaking natural gas wells and subsurface flow; (2) the contamination of surface water and shallow groundwater from spills, leaks, and/or the disposal of inadequately treated shale gas wastewater; (3) the accumulation of toxic and radioactive elements in soil or stream sediments near disposal or spill sites; and (4) the overextraction of water resources for high-volume hydraulic fracturing that could induce water shortages or conflicts with other water users, particularly in water-scarce areas. Analysis of published data (through January 2014) reveals evidence for stray gas contamination, surface water impacts in areas of intensive shale gas development, and the accumulation of radium isotopes in some disposal and spill sites. The direct contamination of shallow groundwater from hydraulic fracturing fluids and deep formation waters by hydraulic fracturing itself, however, remains controversial.
(Goldstein et al., 2014)	*The Role of Toxicological Science in Meeting the Challenges and Opportunities of Hydraulic Fracturing*	"EPA has a study under way to identify chemicals used in hydraulic fracturing and to compile high quality information regarding the chemical, physical, and toxicological properties of the chemicals. EPA's work is not designed to consider issues such as mixtures. One of the most difficult challenges facing toxicologists is predicting the effects of mixtures. Adding to this challenge is that the mixtures will vary from location to location based upon the choice of hydraulic fracturing agents as well as local geology, which will determine hydrocarbon and natural background constituents."

10.1.2 Summary of Information Sources

These studies outline the major potential health risks from hydraulic fracturing and focus on VOC and other chemical (BTEX, metals & metaloids, NORM) exposure. They take into account various distances from operations and base their conclusions accordingly. In general though, a strong theme throughout the literature is that further work needs to be done.

Goldstein et al. (2014) inform the groups of chemical compounds (Silica DPM, VOCs/BTEX, H2S PAH, Biocides/Miscellaneous, Metals/NORM) that occupational exposures associated with upstream oil and gas production by type of operation identified (pad construction, drilling, cementing, stimulation/fracturing, well testing/completion, well servicing, and trucking).

10.1.3 Analysis of Information Sources

It is difficult to outright assess the risk from chemicals involved in hydraulic fracturing. The potential exposure pathways are numerous and include drinking water, skin contact, soil and food, and atmospheric. The exact damage and health risk is largely dependent also on concentration and vector of delivery, and the toxicity potential of the compounds and its derivations, three things which are again are very case-specific. As mentioned early, this strongly suggests the need for full disclosure from operators in case of accidents.

Starting from this broad picture with its many dependencies, we can start by assessing the toxicity of chemicals within the lab. To so this, this report includes material safety and data sheets (MSDS) of a vast number of chemicals involved in hydraulic fracturing. These can be found in section 16. These sheets gives a rough idea of potential risk, but it don not tell the whole story as chemical change and react over time and under the operating conditions of hydraulic fracturing.

In reality, the chemicals we will want to focus on have the following three characteristics: toxicity, persistence, and mobility. It is unknown how these chemicals behave over time and at high pressure. Of note Also of concern are other aromatic hydrocarbons, petroleum distillate products, amines, amides, and acids (NYSDEC 2011).

In terms of empirical and modeled results, the study by (Bloomdahl et al. 2014) looks at worker exposure to VOCs from produced water. This is looking at direct worker safety as opposed to previous studies which focused on community-wide impacts. The study finds that for most situations, the risk level is below OSHA limits, however more research is needed. (Colborn et al. 2011) focuses at the chemicals involved in hydraulic fracturing and attempts to select the most harmful chemicals involved in hydraulic fracturing. The study finds that "many chemicals used during the fracturing and drilling stages of gas operations may have long-term health effects that are not immediately expressed."

On this note of more research, (Werner et al. 2015) echoes this and states that the current state of the literature does not allow for any negative health impacts to be ruled out. (Finkel and Hays 2013) is a broad overview on the potential impacts on health and again sets out a call for further research. (McKenzie et al. 2012) and(McKenzie et al. 2014) strongly suggest that air emissions' impact on human health warrant further study, and while not conclusive, potentially have a non-trivial impact of maternal health as well. On this note, this report aggregated studies that try to quantitatively asses the true costs and benefits of using hydraulic fracturing to develop oil and gas resources. (Jenner and Lamadrid 2013) puts the cost-benefit analysis in terms of a direct comparison with coal and comes to the conclusion that any benefits rely on an thoroughly effective environmental management program.

Finally, (Eaton 2013) comes to the conclusion that the risks are too great for New York and that a ban is appropriate given the lack of research. Indeed, in a December 2014 public health review of hydraulic fracturing, the New York Department of Health came to this conclusion:

> The DOH [Department of Health] Public Health Review finds that information gaps still exist regarding various aspects of HVHF [High Volume Hydraulic Fracturing] activities. Well-designed, prospective, longitudinal studies are lacking that evaluate the overall effect of HVHF shale-gas development on public health outcomes. The existing science investigating associations between HVHF activities and observable adverse health outcomes is very sparse and the studies that have been published have significant scientific limitations. Nevertheless, studies are suggestive of potential public health risks related to HVHF activity that warrant further careful evaluation. Additional population-based research and surveillance, and more studies involving field investigations in locations with active HVHF shale-gas development, would be valuable. (New York State Department of Health 2014)

The full version of the report is a useful resource for aggregation of studies. New York State Department of Health (2014). *A Public Health Review of High Volume Hydraulic Fracturing for Shale Gas Development*. Tech. rep.

10.2 Environmental Risk Analyses

Similar to health impacts, a generalized environmental risk assessment is difficult due to the case-specific risks related to development. However there are some studies which attempt to do so and this report explores them in detail below.

10.2.1 Information Sources

(Sovacool 2014)	"Cornucopia or curse? Reviewing the costs and benefits of shale gas hydraulic fracturing (fracking)"	"The study discusses a series of advantages and disadvantages to hydrofracking. It notes that done properly, shale gas development can enhance energy security and the availability of energy fuels, lower natural gas prices, offer a cleaner environmental footprint than some other fossil fuels, and enable local economic development. However, done poorly production can be prone to accidents and leakage, contribute to environmental degradation, induce earthquakes, and, when externalities are accounted for, produce more net economic losses than profits. The study concludes that the pursuit and utilization of shale gas thus presents policymakers, planners, and investors with a series of pernicious tradeoffs and tough choices."
(Soeder et al. 2014)	"An approach for assessing engineering risk from shale gas wells in the United States"	This study attempts an engineering approach to oil and gas devlopment. "Preliminary findings indicate that shale gas well drilling and hydraulic fracturing techniques are generally safe when properly applied. Incident reports recorded by state environmental agencies suggest that human error resulting from the disregard of prescribed practices is the greatest cause of environmental incidents. This can only be addressed through education, regulations and enforcement."
(Krupnick, Wang, and Wang 2014)	"Environmental risks of shale gas development in China"	"In this paper, we offer a macro assessment of the environmental risks of shale gas development in China. We use the US experience to identify the nature of shale gas development activities and the types of potential burdens these activities may create. We then review the baseline environmental conditions and the effectiveness of environmental regulations in China and discuss the implications of these China-specific factors for risk assessment. We recommend China to conduct a strategic environmental assessment and to consider sector-specific environmental regulations."
(Rivard et al. 2014)	"An overview of Canadian shale gas production and environmental concerns"	"This paper describes the status of shale gas exploration and production in Canada, including discussions on geological contexts of the main shale formations containing natural gas, water use for hydraulic fracturing, the types of hydraulic fracturing, public concerns and on-going research efforts. As the environmental debate concerning the shale gas industry is rather intense in Quebec, the Utica Shale context is presented in more detail."

(Stamford and Azapagic 2014)	“Life cycle environmental impacts of UK shale gas”	This paper looks at the potential impacts in the United Kingdom: "The results suggest that the impacts range widely, depending on the assumptions. For example, the global warming potential (GWP100) of electricity from shale gas ranges from 412 to 1102g CO2-eq./kWh with a central estimate of 462g. The central estimates suggest that shale gas is comparable or superior to conventional gas and low-carbon technologies for depletion of abiotic resources, eutrophication, and freshwater, marine and human toxicities. Conversely, it has a higher potential for creation of photochemical oxidants (smog) and terrestrial toxicity than any other option considered. For acidification, shale gas is a better option than coal power but an order of magnitude worse than the other options. The impact on ozone layer depletion is within the range found for conventional gas, but nuclear and wind power are better options still. The results of this research highlight the need for tight regulation and further analysis once typical UK values of key parameters for shale gas are established, including its composition, recovery per well, fugitive emissions and disposal of drilling waste."

10.2.2 Summary of Information

Many of the above studies qualitatively rather than quantitatively address the risks of hydraulic fracturing. In the end, the general conclusion seems to be that there is no clear cost-benefit result,local jurisdictions need to weigh the costs and benefits for themselves.

10.2.3 Analysis of Information

(Soeder et al. 2014) presents an engineering risk assessment using integrated assessment models IAMS. It attempts to run scenarios and Monte-Carlo simulations to quantify the risk to the environment from shale gas drilling. It comes to the conclusion that human error is the greatest cause of environmental incidents.

A study by (Sovacool 2014) tries to take a broad view of the pros and cons of hydraulic fracturing it comes to mixed conclusions.

> "...shale gas development can enhance energy security and the availability of energy fuels, lower natural gas prices, offer a cleaner environmental footprint than some other fossil fuels, and enable local economic development. However, done poorly production can be prone to accidents and leakage, contribute to environmental degradation, induce earthquakes, and, when externalities are accounted for, produce more net economic losses than profits. The study concludes that the pursuit and utilization

> of shale gas thus presents policymakers, planners, and investors with a series of pernicious tradeoffs and tough choices."

States like New York and Vermont have decided that hydraulic fracturing is too risky, however states like Colorado, Texas, California, and Pennsylvania have embraced it with relish and have suffered environmental impacts. Overall the federal government has taken its time coming to a conclusion, which may be the best process forward.

For an international perspective (Krupnick, Wang, and Wang 2014) looks at a cost-benefit analysis with an eye towards China, (Rivard et al. 2014) looks at Canada, and (Stamford and Azapagic 2014) looks at life-cycle impacts in the UK. These studies could potentially be replicated in Mexico.

11 Regulations

In the United States, the oil and gas sector is regulated primarily through the states, which leads to significant differences in the content, scope, and nature of regulations. Although these differences allow for many case studies, they also complicate the task of finding the best practices for conducting activities within this sector (Richardson et al. 2013). Moreover, the recent public opposition regarding hydraulic fracturing, is causing a constant change in regulations. For example, California has an extensive history of oil and gas development and only finalized its rules for hydraulic fracturing in December of 2014 (Pavley and Leno 2014). As these regulations are some of the most recent in the United States, this report will refer to them when applicable. However, they should not be taken as sufficient to protect the environment and health given that even the most "stringent" regulations may fall short of these goals.

11.1 Information Sources

(Richardson et al. 2013)	*The State of State Shale Gas Regulation*	" The core of this report is a catalog of a range of state regulations-25 regulatory elements in all- relevant to shale gas, across 31 states with actual or potential shale gas production. These data are an important new resource for understanding how states are managing the risks of shale gas development."
(Pavley and Leno 2014)	*Senate Bill No. 4, Oil and gas: well stimulation*	This bill sets forth the key hydraulic fracturing regulations in California.

(Melo-Martín, Hays, and Finkel 2014)	"The role of ethics in shale gas policies."	This study: "argue[s] that policy makers have a prima facie duty to minimize false negatives based on three considerations: (1) protection from serious harm generally takes precedence over the enhancement of welfare; (2) minimizing false negatives in this case is more respectful to people's autonomy; and (3) alternative solutions exist that may provide many of the same benefits while minimizing many of the harms."
(Holahan and Arnold 2013)	"An institutional theory of hydraulic fracturing policy"	This study "theorize[s] that the point-source pollution characteristics of conventional drilling allowed integration contracts and well space requirements to minimize local negative environmental externalities as an unintended byproduct of minimizing common-pool economic wastes. The non-point source pollution characteristics of fracking, however, make these institutions insufficient to minimize negative environmental externalities associated with drilling in shale plays, because the economic waste problem is different. If policymakers understand the crucial differences between conventional oil and gas plays and shale plays and the drilling technologies applied to them, they should be better equipped to craft fracking regulatory policies that internalize problematic externalities."

11.2 Summary of Information

The literature is presented in two categories with the first being an overview the existing status of U.S. regulations which are subject to constant change. The second category addresses theories of regulation, namely that care should be taken in concert with uncertainty.

11.3 Analysis of Information

Proper regulations and standards require location specific factors that cannot necessarily be accounted for by looking at other locations. Jurisdiction of oil and gas in the U.S. is largely dependent on location. In general, if the lands are Federal, the U.S. Environmental Protection Agency (US EPA) has jurisdiction. The overarching laws are the Clean Air Act, Clean Water Act, Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), National Environmental Protection Act, Safe Drinking Water Act (SWDA), Re- source Conservation and Recovery Act (RCRA), and the Emergency Planning and Community Right to Know Act. These overarching set of laws manage emissions, waste disposal, and accidental and remediation response.

However oil and gas activities have received several exemptions from hazardous waste laws (RCRA) and hydraulic fracturing has received an exemption from safe water injection rules:

SEC. 322. HYDRAULIC FRACTURING.
Paragraph (1) of section 1421(d) of the Safe Drinking Water Act (42 U.S.C. 300h(d)) is amended to read as follows:

(1) UNDERGROUND INJECTION.-The term 'underground injection' - (A) means the subsurface emplacement of fluids by well injection; and (B) excludes-

(i) the underground injection of natural gas for purposes of storage; and
(ii) 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.

[a]

[a]United States Congress (2005). "Energy Policy Act of 2005". In: *Public Law*. URL: `https://scholar.google.com/scholar?hl=en\&q=energy+policy+act+of+2005\&btnG=\&as\_sdt=1\%2C5\&as\_sdtp=\#1`

As such this report will mainly focus on state regulation and the commissions that drafted them namely state oil and gas commissions. The composition and authority of these agencies vary within states . We will focus on the Colorado Oil and Gas Conservation Commission (COGCC), the Texas Railroad Commission (TRRC), the Pennsylvania Department of Environ- mental Protection (PA DEP), and the Department of Oil and Gas and Geothermal Resources (DOGGR). In each of these states authority over all environmental issues is shared between the US EPA (federal level) and local organizations.

As stated by, (Melo-Martín, Hays, and Finkel 2014) policies should be based on three principles:

- " protection from serious harm generally takes precedence over the enhancement of welfare;"
- "minimizing false negatives in this case is more respectful to people's autonomy; and"
- "alternative solutions exist that may provide many of the same benefits while minimizing many of the harms."

A study by (Holahan and Arnold 2013) sets up the differences between conventional and unconventional plays in regards to what needs to be regulated. The study suggests that particular attention needs to paid to unconventional developments due to the fact that water management plays a significantly different role.

12 Analysis of Violations

To demonstrate actual risks, we analyzed data from Pennsylvania (PA DEP 2014a) in order to answer the following questions:

- Which regulations are most often violated?
- What has been the actual consequences of violating these regulations?
- Have fines been effective?

12.1 Information Sources

(PA DEP 2014a)	*PA DEP Oil & Gas - Statewide Data Downloads By Reporting Period*	"This data is provided by the Pennsylvania's Oil and Gas Act which requires unconventional well operators to submit production reports to the Department of Environmental Protection (DEP) biannually."

12.2 Analysis

To answer these questions, this report evaluated 17,493 administrative (10,630 or 61%) and environmental health and safety (6,863 or 39%) shale gas violations from the state of Pennsylvania from 2010 to 2014. This data set does not include all the violations that occurred during that period and for all the wells that were drilled and currently exist in the state, and thus, represents an underestimate of the actual number of violations that have occurred to date. The dataset includes the name of companies who are the worst performers (CHESAPEAKE APPALACHIA LLC) with 572 violations, or 3% of the total, is the worst violator, with fines over ten different counties and forty-nine townships throughout the state), fines (most expensive 'unique' fines, and most expensive 'average' fines), geo-spatial location of well violations, and different types of administrative and environmental health and safety violations. A brief analysis of the data that was available for the state of Pennsylvania is developed below.

The Pennsylvania data set includes 17,493 violations from forty (out of sixty seven) counties and 546 townships in the state. The years for which it includes violations range from 2010 to 2014 with 20%, 29%, 24%, 17%, and 10% of them occurring in each year respectively (2010 - 2014). The data is divided into administrative (61%), and environmental, health and safety violations (39%). There are 180 unique violations out of which 99 are administrative (55%), and 81 (45%) environmental. Only 14,291 violations have well geo-location data (county and township). Besides data regarding violation types, there is also information regarding violation and resolution dates, fine magnitude ($), and well operator.

Figure 18: Frequency of Violations by Violation Code

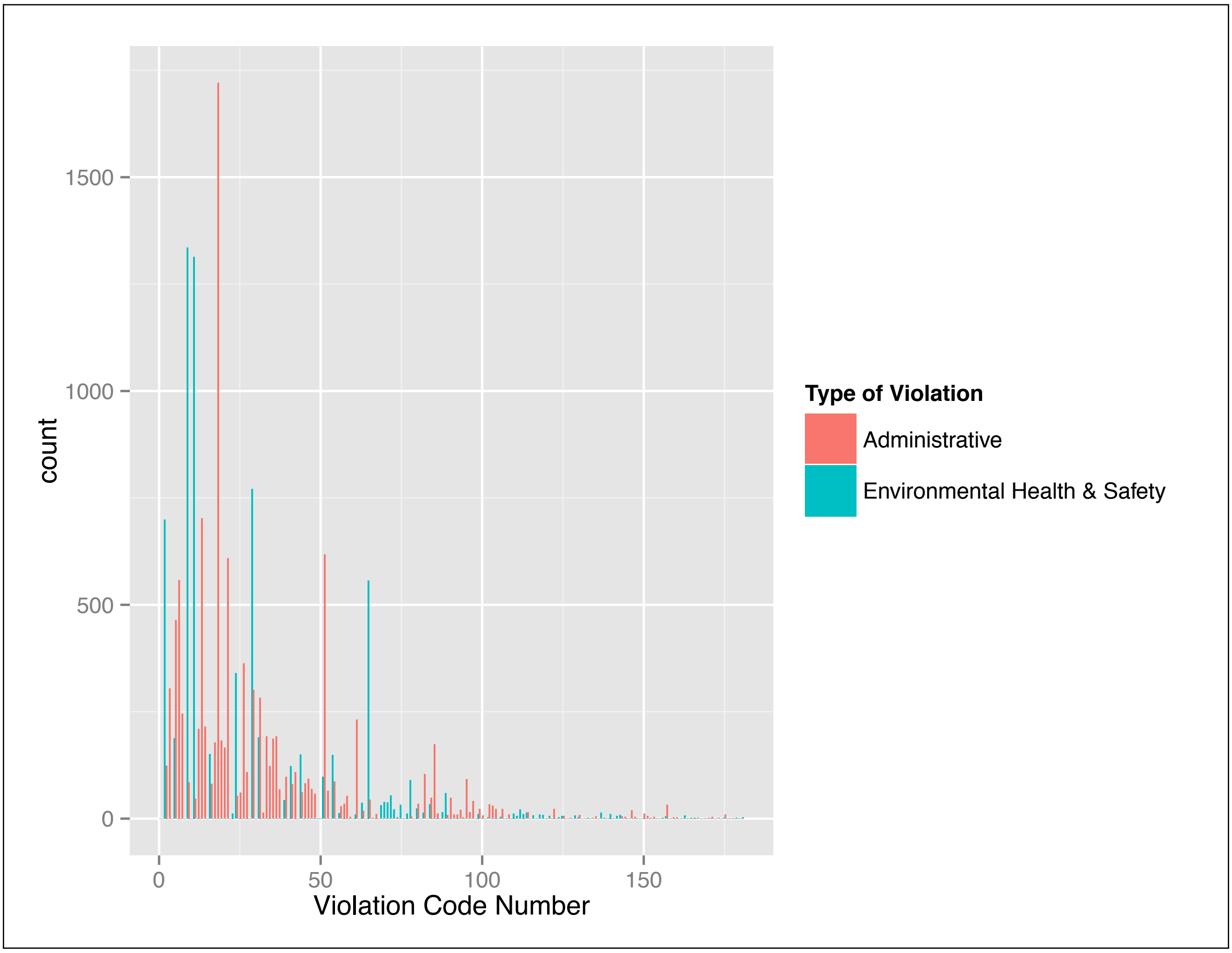


Table 46: Summary of Violations

Total Violations	17,493
Administrative	10,630 (61%)
Environmental Health & Safety	6,863 (39%)

From figure 19 (below) we can observe the operators with the greatest number of violations are not necessarily the ones with the greatest geographical representation, nor the ones with the largest fines. Shown below are operators and violation types which accrue the largest fines.

Without discriminating between administrative or environmental violations, the five most frequent violations are the failure to plug a well upon abandonment (1,720 occurrences or 9.8% of the total), failure to minimize accelerated erosion, implemented environmental safety (E&S) plan and maintain E&S controls (1,335 occurrences or 7.6% of the total), failure to properly store, transport, process of dispose of residual waste (1,314 occurrences or 7.5% of the total), failure to adopt pollution prevention measures required or prescribed by DEP by handling materials that create a danger of pollution (771 occurrences or 4.4% of the total), and failure to submit well record within 30 days of completion of well 702 occurrences or 4% of the total).

12.2.1 Well Operators and Bad Actors

There are 570 well operators in the data set, and 35 of them account for over 50% of the total number of violations. The worst operator is 'CHESAPEAKE APPALACHIA LLC' (3% of all violations) which has committed violations (572) in over ten different counties and forty-nine townships throughout the state. Most violations of this well operator are related to environmental, health, and safety (55%), with the rest (45%) being administrative. Table 1 shows more information about the ten worst shale operators in Pennsylvania.

Figure 19: Operators with the largest number of violations.

	Operator Name	Counties (Townships)	Violations (% of total)	Environmental*	Administrative*	Total Fines ($)
1	*CHESAPEAKE APPALACHIA LLC*	10 (49)	572 (3.3%)	315 (55%)	257 (45%)	$5,767,275
2	*CABOT OIL & GAS CORP*	4 (15)	484 (2.7%)	227 (47%)	257 (53%)	$1,284,064
3	*SENECA RESOURCES CORP*	13 (34)	393 (2.2%)	174 (44%)	219 (56%)	$8,234,899
4	*RANGE RESOURCES APPALACHIA L*	14 (44)	375 (2.1%)	244 (65%)	131 (35%)	$3,030,175
5	*CHIEF OIL & GAS LLC*	13 (34)	372 (2.1%)	176 (47%)	196 (53%)	$533,600
6	*CATALYST ENERGY INC*	5 (15)	311 (1.9%)	103 (33%)	208 (67%)	$1,501,750
7	*HOMELAND ENERGY VENTURES L*	3 (4)	295 (1.7%)	68 (23%)	227 (77%)	$1,809,900
8	*XTO ENERGY INC*	11 (36)	298 (1.7%)	155 (54%)	134 (46%)	$698,480
9	*TALISMAN ENERGY USA INC*	4 (15)	279 (1.6%)	120 (43%)	159 (57%)	$1,748,860
19	*TITUSVILLE OIL & GAS ASSOC INC*	3 (4)	258 (1.5%)	121 (47%)	137 (53%)	$1,748,860

* Note: Environmental and administrative numbers represent proportions (and percentage) of the total number of violations per operator.

12.3 Fines

Fines are usually decided in civil court but criminal charges can also be brought against operators. The amount varies greatly, but a general formula that Pennsylvania follows is:

> Penalty Amount = Impact \$ + Willfulness \$ + Commonwealth's Costs + Violator's Savings + Viol History \$ - Cooperation \$ (PA DEP 2012).

There are two types of analysis that can be done regarding fines. The first is analyzing the fines that are the most expensive in section 12.3.1, and the second is evaluating the companies with the largest and most expensive fines in section 12.3.2.

12.3.1 Most Expensive Fines

Due to the nature of the data set it was not possible to determine the unique and exact value of each type of violation. For example, a violation that is documented as discharge of 'pollutional materials into the commonwealth' could have several different violation costs depending on the pollution discharged, and location of discharge, among other things. Thus, it was not possible to know the exact cost of each distinct violation type. Here we first show the five unique most expensive violations (without more details), and then the five most expensive violations on average.

The five most expensive fines in the data set include 'discharge of pollutional material to waters of commonwealth' ($US 900,000), 'excessive casing seat pressure' ($US 900,000), 'inadequate or improperly installed BOP, other safety devices, or no certified BOP operator' ($US 353,419), 'Oil and Gas Act General Violation' ($US 353,419), and 'Hazardous Well Venting' ($US 353,419).

On average (total number of violations - by violation code/total amount fined - by violation code) the most expensive violations were 'inadequate or improperly installed BOP, other safety devices, or no certified BOP operator' ($US 94,179/violation), 'pipeline installed less than 25 feet from the stream bank without a waiver' ($US 91,666/violation), 'failure to maintain encroachment' ($US 67,348/violation), 'well drilled or operated without a permit or registration from DEP' ($US 64,016/violation), and 'Hazardous Well Venting' ($US 53,817/violation).

12.3.2 Most Expensive Violators

Figure 20: Most Expensive Violators

	Operator Name	Counties (Townships)	Total Number of Violations	Environmental*	Administrative*	Total Fines ($)
1	*NFG Midstream Trout Run LLC*	1 (1)	108	62 (58%)	46 (42%)	$14,250,000
2	*REGENCY MARCELLUS GAS GATHERING LLC*	1 (1)	175	91 (52%)	84 (48%)	$11,800,516
3	*SENECA RESOURCES CORP*	13 (174)	393	174 (44%)	219 (56%)	$8,234,899
4	*LASER NORTHEAST GATHERING CO LLC*	1 (1)	64	9 (61%)	25 (39%)	$6,749,502
5	*WILLIAMS FIELD SVC CO LLC*	2 (2)	144	93 (65%)	51 (35%)	$5,947,632

* Note: Environmental and administrative numbers represent proportions (and percentage) of the total number of violations per operator.

The most expensive violators commit their violations in fewer areas than the most frequent violators (Table 1), and also commit less violations, but according to the dollar amount on their fines, their violations are more serious. The most common violations amongst this group of violators is 'failure to minimize accelerated erosion, implement E&S plan, maintain E&S controls. Failure to stabilize site until total site restoration under OGA', 'failure to adopt pollution prevention measures required or prescribed by DEP by handling materials that create a danger of pollution', 'failure to design, implement or maintain BMPs to minimize the potential for accelerated erosion and sedimentation', 'failure to properly store, transport, process or dispose of a residual waste', and 'discharge of pollutional material to waters of Commonwealth'.

12.3.3 Geospatial Violation Analysis

The counties with the most violations are McKean, Forest, Venango, Warren, Jefferson and Clarion. These are all located in a cluster of Pennsylvania on the Northwestern part of the state above some of the thinnest Marcellus shale locations. Most of the violations in these six counties are administrative (4,442 or 68% of the total number of violations in these six counties), with the rest being related to environmental health and safety. It is worth noting that the map with well locations [B] does not include wells drilled at the end of 2013, or 2014. The violations data that is included in our analysis [C] and [D] does not include data for all wells in the state, but only for wells for which there was available violations data. The spatial correlation that can be inferred from these maps is inconclusive. Without doing further analysis it would be difficult to suggest that most violations occur in areas where the Marcellus Shale is the thinnest, or that the wells located in the Northeastern part of the state have less number of violations. Simply, only if violation data were available for every well in the state would one be able to make decisive and sound conclusions about the spatial correlations presented below.

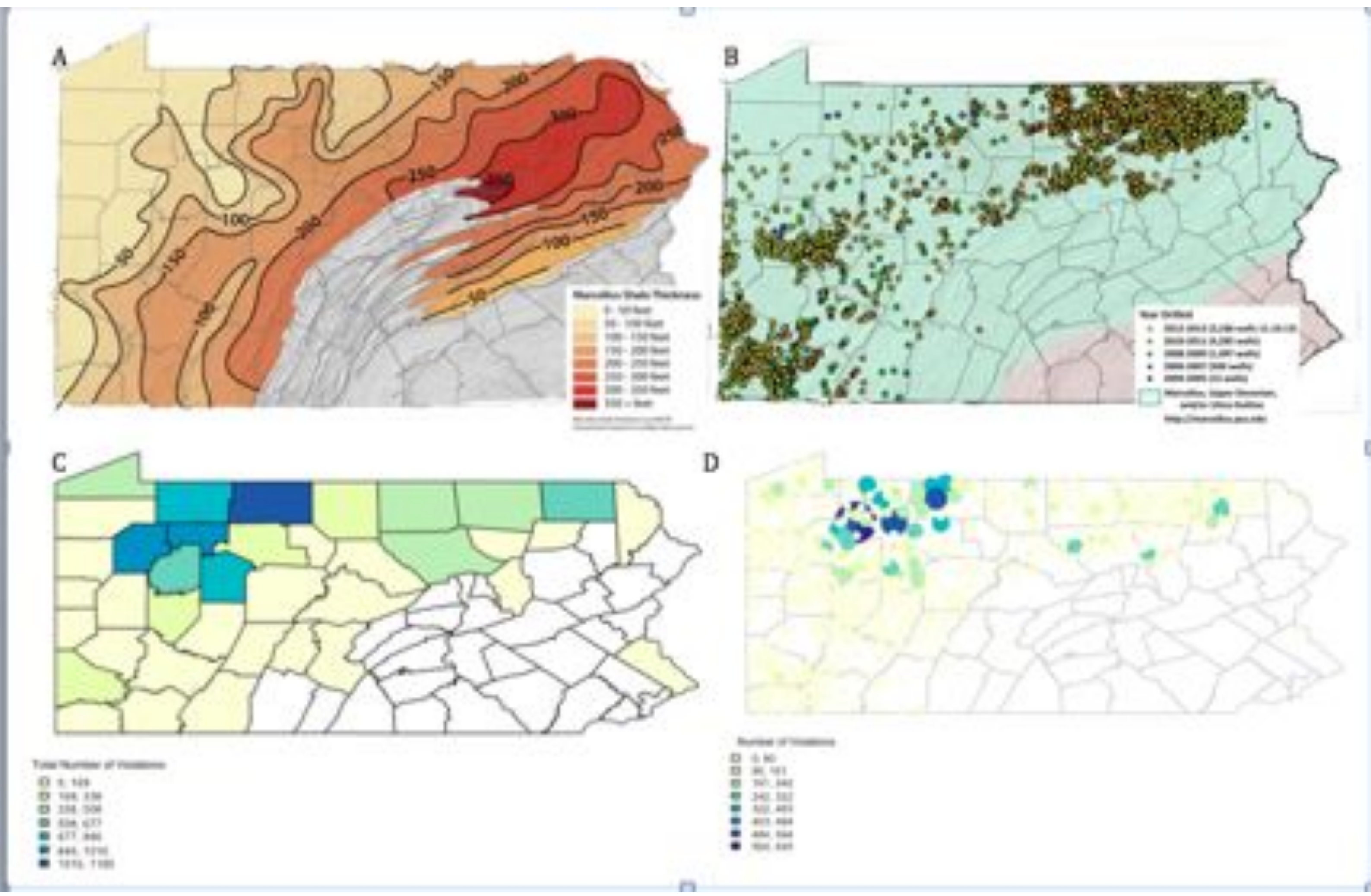


Figure 21: Marcellus Shale Thickness [A], Wells Drilled [B], Total Number of Violations by County [C], and Total Number of Violations by Township [D]

12.3.4 Environmental Health and Safety Violations

6,863 or 39% of the violations in this analysis were environmental. The most frequent environmental health and safety violations include 'failure to properly store, transport, process of dispose of residual waste' (20%), 'failure to minimize accelerated erosion, implemented environmental safety (E&S) plan and maintain E&S controls' (20%), 'failure to adopt pollution prevention measures required or prescribed by DEP by handling materials that create a danger of pollution' (11%), 'discharge of pollutional materials to waters of commonwealth' (10%), and 'failure to properly control or dispose of industrial or residual waste to prevent pollution of the waters of the Commonwealth' (8%). The cost of these top-five environmental violations is higher on average than the rest of the environmental violations. A 'top-five' environmental violation is worth $US 7,812/violation, with other violations being worth $568 less ($7.244). Of the 'top-five' violations, the most expensive violation is 'discharge of pollutional material to waters of commonwealth' ($US12,837/violation), followed by 'failure to minimize accelerated erosion, implemented environmental safety (E&S) plan and maintain E&S controls' ($US 9,782/violation), 'failure to adopt pollution prevention measures required or prescribed by DEP by handling materials that create a danger of pollution' ($US 8,942/violation), 'failure to properly store, transport, process of dispose of residual waste' ($US 4,266/violation), and 'failure to properly control or dispose of industrial or residual waste to prevent pollution of the waters of the Commonwealth' ($US 3,590/violation). Of all possible environmental violations the most expensive violation is 'discharge of pollutional material to waters of commonwealth' with a cost of $US12,837 per violation.

Figure 22: Histogram of Environmental Violations by Code (Total: 6,863)

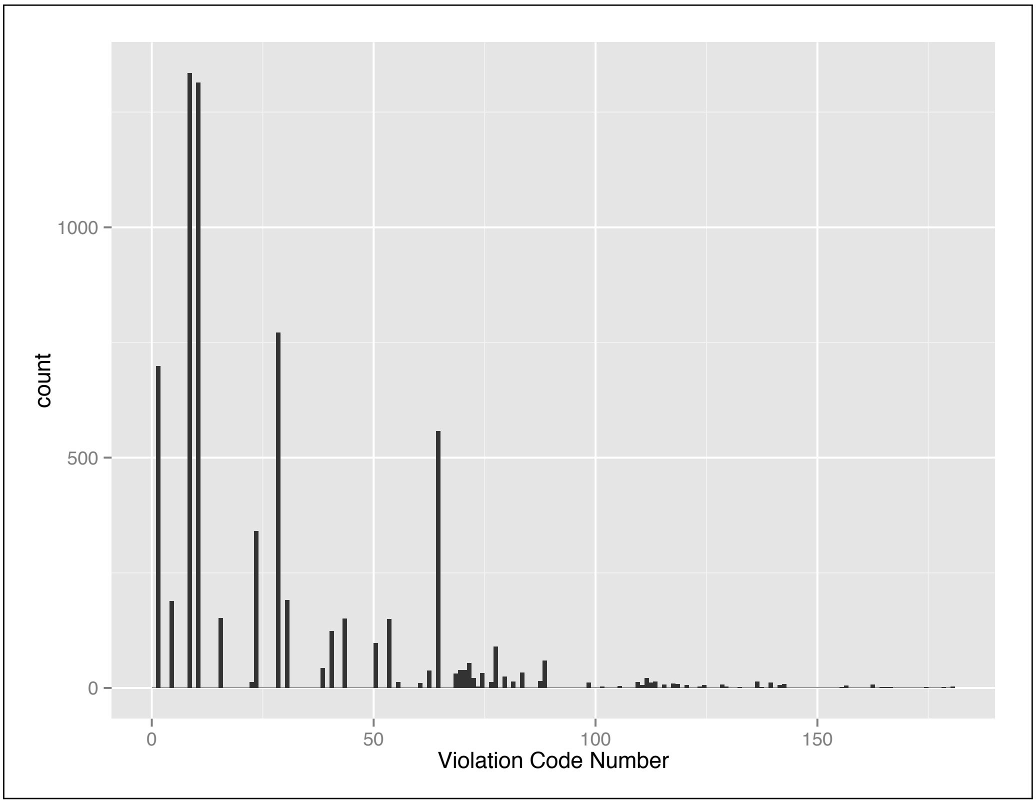


Table 47: Top 5 Environmental Violations

Fine Number	Description	Number of Incidents in Data Set
8	Failure to minimize accelerated erosion, implement E&S plan, maintain E&S controls (20%)	1335
10	Failure to properly store, transport, process or dispose of a residual waste (20%)	1314
28	Failure to adopt pollution prevention measures required or prescribed by DEP by handling materials that create a danger of pollution (11%)	771
1	Discharge of pollultional material to waters of Commonwealth (10%)	699
64	Failure to properly control or dispose of industrial or residual waste to prevent pollution of the waters of the Commonwealth (8%)	557

12.3.5 Administrative Violations

Most (61%) of the violations in this analysis were administrative (10,630). The most frequent administrative violations include 'Failure to plug a well upon abandonment' (16%), 'failure to submit well record within 30 days of completion of drilling' (7%), 'failure to install, in a permanent manner, the permit number on a completed well' (6%), 'failure to achieve permanent stabilization of earth disturbance activity' (4%), and 'failure to submit annual production report' (5%). Differently from the environmental violations (above), the 'top-five' most frequent administrative violations are not the most expensive.

On average, the five most frequent violations are less expensive ($US 2,568/violation) than less frequent violations ($US 5,484/violation). Although 'failure to plug a well upon abandonment' is the most frequent overall violation, the fine is relatively small, only being worth $US 1,307/violation. The most expensive 'top-five' violation is 'failure to achieve permanent stabilization of earth disturbance activity' ($US 11,003/violation), followed by 'failure to submit well record within 30 days of completion of drilling' ($US 1,476/violation), 'failure to install, in a permanent manner, the permit number on a completed well' ($US 1,617/violation), and 'failure to submit annual production report' having no cost at all ($0/violation). Although it is not one of the most frequent violations, 'pipeline installed less than 25 feet from the stream back without a wavier' is the most expensive administrative violation ($US 91,666/violation).

Figure 23: Histogram of Administrative Violations by Code (Total: 10,630)

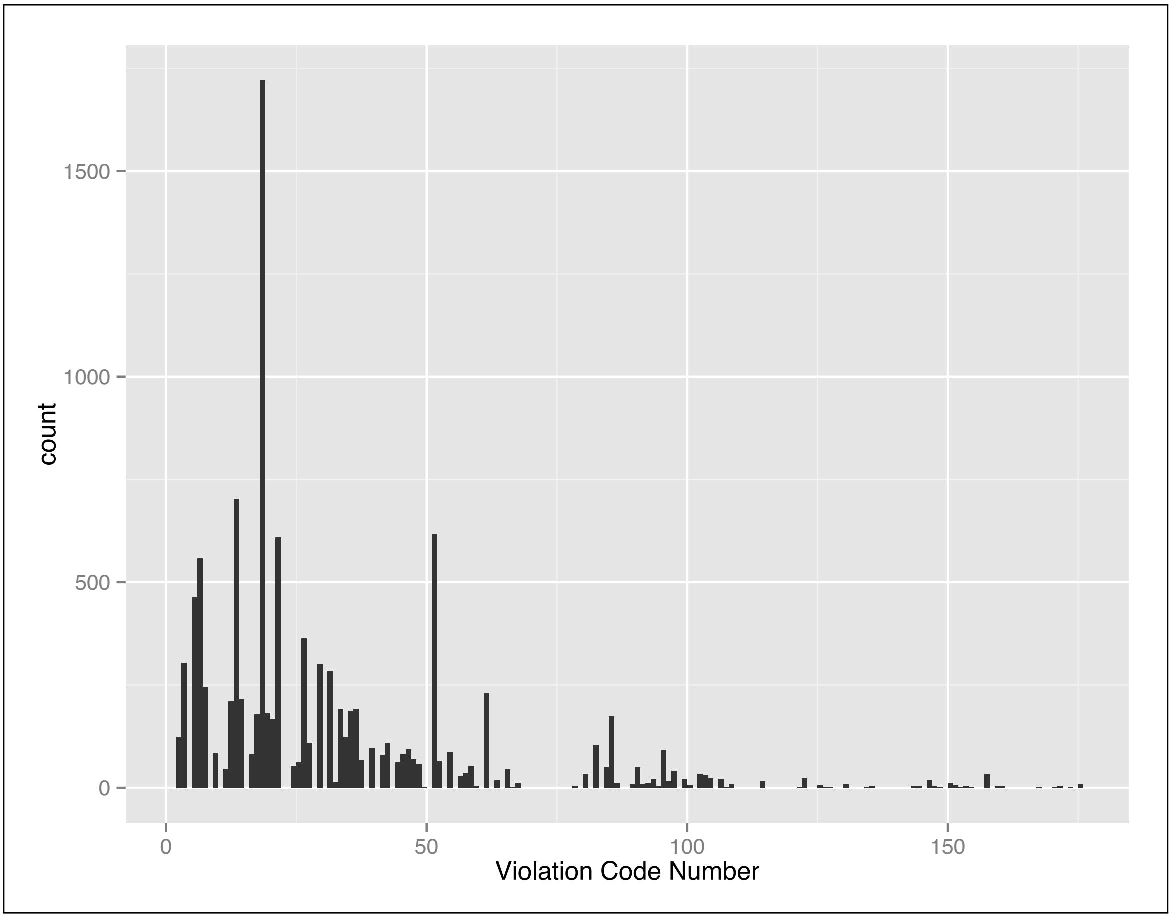


Table 48: Top 5 Administrative Violations

Violation Number	Description	Number of Incidents in Data Set
18	No.18: Failure to plug a well upon abandonment (16%)	1720
13	No.13: Failure to submit well record within 30 days of completion of drilling (7%)	702
21	Failure to install, in a permanent manner, the permit number on a completed well (6%)	609
6	Failure to achieve permanent stabilization of earth disturbance activity (4%)	464
5	Failure to submit annual production report (5%)	558

12.4 Enforcement and Interviews with Regulators

As hydraulic fracturing regulations and enforcement capacity vary widely across different states so does the capacity to enforce the regulations in place. In most cases, the number of inspectors is insufficient to keep pace with the growing number of wells in each state (with the exceptions being North Dakota and Pennsylvania). The generally recognized number of inspectors per well needed to conduct sufficient yearly inspections is approximately 1 inspector per 1000 wells, or 1000 wells/inspector, and active wells should be inspected once each year (Western Organization of Resource Councils 2013). However, the average number of wells per inspector for the five states studied was 1100 wells/inspector. Additionally, number of violations was difficult to track down as not many states report this data, or states are unable to process all violations accurately due to the insufficient number of field inspectors.

12.4.1 Information Sources

(Western Organization of Resource Councils 2013)	*Law and Order in the Oil and Gas Fields: A Review of the Inspection and Enforcement Programs in Five Western States*	This report reviews regulatory enforcement in the Western U.S. and find "state and federal oil and gas inspection and enforcement programs are still consistently understaffed and seldom take enforcement actions. When enforcement actions are taken, fines and penalties are almost always trivial."
(Colorado Oil and Gas Conservation Commission 2014b)	*Oil and Gas Conservation Commission Staff Reports*	These are the Colorado Oil and Gas Comissions' monthly work updates.
(Texas Railroad Commission 2014)	*Texas RRC - Enforcement Activities - Report on Oil and Gas Field Operations' Violations and Enforcement*	This is quarterly reportson oil and gas enforcement data from the Texas Railroad Commission.

Typically, violations are issued by state agencies as a last resort and financial penalties are low, as agencies are often seeking to collaborate and comply with the oil and gas drilling industry. This raises concerns about effective and timely spill cleanup efforts, and effectiveness of sanctions in general to curb environmentally destructive practices in the industry. A recent data analysis on violations and enforcement activities was conducted by the Western Organization of Resource Councils' "Law and Order in the Oil and Gas Fields: 2013 Report" (Western Organization of Resource Councils 2013).

The state of US regulations on fracking is currently changing rapidly, alongside a rapid increase in wells being drilled. This makes for a dynamic and constantly shifting regulatory and enforcement climate, which can lead to difficulties gathering most up-to-date data. Sources often conflict in their reporting data on enforcement, and new laws have come into effect in 2015. Additionally, many state regulations are being reconsidered and rewritten following the New York State fracking ban (the result of a 184-page Department of Health report detailing environmental and public health consequences of fracking). Federal regulation is also being called for to provide uniform standards and protections (through the Bureau of Land Management) for communities in the face of variable state enforcement capacities.

Table 50: Number of Inspectors and Wells

State,	Number of Wells,	Number of Inspectors,	Wells/Inspector,
California,	54,665	64	854
Colorado	52,947	27	1961
North Dakota	16,126	32	504
Pennsylvania	9,606	75	128
Texas	319,604	159	2010

12.4.2 Colorado

Colorado's enforcement body, the Colorado Oil and Gas Conservation Commission (COGCC), may have relatively strong regulatory policies in place. Representatives from industry, engineering, and environment have leadership roles in the COGCC, and a strong environmental/conservation ethos in the state creates public demand for transparency and enforcement documentation. In 2014, the 27 Colorado field inspectors inspected 30,675 wells. 167 violations were reported, 185 complaints, and 759 spills (averaging about 2 spills per day), according to the December 15, 2014 Staff Report (Colorado Oil and Gas Conservation Commission 2014b). COGCC recently requested 5 additional inspectors from the Governor's Task Force (GTF), citing a seven-state survey on the ratio of active wells to inspectors. The basis of 5 additional inspectors and 1.1 new inspectors per year (to keep up with current drilling growth of about 2000 wells/year) was determined by averaging the 7 states ratios: 1,621 wells/inspector.

The Deputy Director of Field Operations for the COGCC, Dave Kulmann, advises other states and countries considering implementing a fracking program that

> "this is very technical stuff and it is important to understand this technology while designing the regulations."

In a phone interview, he commented on the recent expansions in drilling activity, inspections, and enforcement policies at the COGCC. As part of a constant effort to satisfy the active environmental community demands in the state and remain accountable to constituent concerns, a new criteria for rejecting drilling permits was adopted in November 2014, so that inadequate information submitted by operators will no longer be accepted. The COGCC maintains a robust public database of complaints filed and resolutions, and holds regular public information sessions. However, some proposed projects to streamline complaint resolution intended to take effect in 2015 require additional personnel, which have been requested through the GTF. The legal code guiding COGCC policy is the Colorado Oil and Gas Conservation Act, available on the COGCC website under "Rules" `http://cogcc.state.co.us`.

12.4.3 Pennsylvania

In Pennsylvania, 2014 data shows that 1,365 new wells were drilled. 4,965 facilities were inspected for a total of 11,171 well inspections, with 411 violations (PA DEP 2014a). 9,606 unconventional wells are currently active (11,938 wells including conventional), served by 75 field inspectors. The DEP oil and gas enforcement program is entirely funded by well permit fees as of 2010; permit fees were increased in 2009 in order to expand compliance and enforcement staff to keep pace with increased drilling activity. The Pennsylvania Department of Environmental Protection (PA-DEP) makes enforcement data publicly available through the Environment Facility Application Compliance Tracking System (eFACTS) portal. Through this website users can find inspection and pollution prevention visits documented, as well as any enforcement actions when violations are noted. Users are able to search by Client or Facility ID to locate enforcement actions including fines and other sanctions on drilling operators. Drilling operators are subject to environmental regulations and, according to eFACTS "reporting is a fundamental part of all environmental protection programs."

John Ryder, Director of the Bureau of District Oil and Gas Operations for the DEP, emphasizes the vast number of people necessary to work on regulating and implementing enforcement activities in such a dynamic industry. He acknowledges the need for strong teamwork across the DEP, in all regulatory programs, to accomplish the enforcement work on:

"complicated regulatory issues associated with the unconventional shale development process."

Additional pieces of advice offered include the following:

> 1. In 2012, Pennsylvania's legislature updated its oil and gas law through the passage of Act 13 to address some of the recent technological advances in oil and gas exploration and production in this state. The Office of Oil and Gas Management in the Pennsylvania Department of Environmental Protection has also updated portions of the oil and gas regulations and, in fact, is continuing to advance additional regulatory amendments that ensure the regulatory structure aligns with and assists in the implementation of state law. The statutory and

regulatory structure has enabled Pennsylvania to effectively regulate the oil and gas industry in Pennsylvania with limited federal oversight.

2. As the regulation of the oil and gas industry has advanced in Pennsylvania, so too has the amount of data that the PA Department of Environmental Protection collects, tracks and utilizes. Any governmental body that is beginning the process of developing an effective regulatory program should devote considerable attention early in the process to what data it intends to collect, how it intends to collect the data, what form (i.e., databases vs. GIS layers) it intends to collect and how it plans to ultimately use the data.

3. Finally, it is important to operate in a transparent manner and build effective working relationships with the public and various stakeholders that are involved or interested in oil and gas related activities.

12.4.4 Texas

If Texas were to meet the 7-state average cited in the Colorado report, it would require 66 additional inspectors to have 1,621 wells/inspector. Information on enforcement activities in the oil and gas operations is listed on the Texas Railroad Commission (RRC) website, which states that "Rider 15 of the General Appropriations Act (83rd Legislative Session) requires the Railroad Commission of Texas to publish a quarterly report about Oil and Gas enforcement data on its website."

According to the Texas RRC Communications and Outreach department, the Oil and Gas Regulatory and Cleanup fund (OGRC) is "funded by the oil and gas industry, not taxpayers, through fees for permits, oil and gas production regulatory fees, sales of salvageable equipment, reimbursement for plugging and remediation costs and surcharges. As activity in the field has increased over the last decade the need for greater regulatory oversight has grown along with it. Additional inspectors benefit the public by ensuring operators are in compliance with rules and regulations and serve as a resource to local communities. Over the past several legislative sessions, the Commission has requested additional resources for inspectors [as well as additional inspectors].

" When violations are alleged, the following enforcement actions are taken: If operators do not come into compliance with our rules after being cited for an alleged rule violation, one of the most effective regulatory enforcement tools Commission staff have are severances or sealing in oil and gas leases. A Railroad Commission severance or seal essentially shuts down an operator's business by preventing that operator from transporting oil or gas from a lease.

Because the Commission conducts inspections by lease and oil leases may contain numerous wells, a Railroad Commission seal could shut in hundreds of oil wells even though only one well might be in violation. After receiving notice that their lease may be sealed based on the operator's alleged violation of Commission rules, most operators come into compliance with our rules. For those who have not, district office staff recommends enforcement action which may include administrative penalties or fines.

It is important to note from the link above just how effective severances have been as an enforcement tool for Railroad Commission staff. For the 10-year period 2004-2013, 62.2% of violations were corrected by the operator promptly upon notice that their lease would be severed or sealed with no further action needed by the Commission. Another 32.4% were resolved following issuance of a severance/seal order. To accurately report on the Commission's enforcement actions, it is important to demonstrate how effective just the threat of a severance or seal order is in bringing operators into compliance with our rules."

Figures 24 and 25 show some of the statistics for Texas from the Texas Railroad Commission.

Figure 24: Texas Violation Data,(Texas Railroad Commission 2014)

Report on Oil and Gas Field Operations' Violations and Enforcement

CHART 1: OIL AND GAS FIELD OPERATIONS DATA

The data below does not track the identification of a specific violation to enforcement action, as detailed in Chart 3, but rather is time-specific aggregate data.

	FY 2014 Quarter 1	FY 2014 Quarter 2	FY 2014 Quarter 3	FY 2014 Quarter 4	FY 2014 Total
Number of oil and gas inspections performed	32,284	30,416	33,455	34,657	130,812
Number of alleged violations identified through oil and gas inspections	15,466	13,522	16,881	16,516	62,385
Number of oil and gas complaints received	182	161	210	201	754
Number of oil and gas complaints resolved	215	157	159	193	724
Number of pipeline severances/seal orders issued	2,785	2,951	3,130	2,675	11,541
Number of repeat oil and gas violators based on a seven-year look back	26	25	25	30	106

Figure 25: Detailed Texas Violation Data,(Texas Railroad Commission 2014)

CHART 3: OIL AND GAS ENFORCEMENT AND DOCKET DATA					
The data in Chart 3 does not track the identification of a violation listed in Chart 1 to penalty action. This chart contains time-specific aggregate data. The number of oil and gas violations sent to the Office of General Counsel for docketing are not necessarily related to the number of enforcement dockets created in the same time period. Additionally, each docket may contain multiple violations.					
	FY 2014 Quarter 1	FY 2014 Quarter 2	FY 2014 Quarter 3	FY 2014 Quarter 4	FY 2014 Total
Number of alleged oil and gas violations sent to Office of General Counsel Enforcement	390	365	301	1,122	2,178
Severity of oil and gas violation, either major or minor (Major/Minor)	261 Major/129 Minor	209 Major/156 Minor	236 Major/65 Minor	1,049 Major/73 Minor	1,755 Major/423 Minor
Number of oil and gas enforcement dockets	77	65	65	70	277
Amount of final oil and gas enforcement penalties assessed	$477,786.92	$607,452.00	$622,902.32	$908,582.00	$ 2,616,723.24

12.4.5 Other

The Western Organization of Resource Councils (WORC) published an update in 2013 to their Law and Order in the Oil and Gas Fields reports, indicating that despite incremental improvements in inspection activity, it is not enough to keep pace with the oil and gas industry's expansion. In 2011 the federal General Accountability Office added the oil and gas program to it's "list of programs at high risk for waste, fraud, abuse, mismanagement, or in need of broad reform.

> " Today's inspection efforts don't change previous report findings– that "state enforcement programs are still consistently understaffed and seldom take enforcement actions. When enforcement actions are taken, fines and penalties are almost always trivial"

in relation to profits made by drilling operators (US Government Accountability Office 2013). Policies that establish maximum amounts of fines or penalties are outdated, and public access to information remains uneven across state agencies. Much work remains to be done in strengthening enforcement agencies' personnel numbers, meeting budget requirements, and addressing agency attitudes towards drilling to apply more robust inspection standards. Recommendations from the report include implementing inspection fees on operators to fully fund inspection and enforcement programs; better public documentation of inspections, violations, and enforcement; and increasing enforcement penalties so that they are sufficient to deter future violations. In particular, not all states track and report violations and enforcement penalties assessed, which makes data on noncompliance difficult to access.

However regulations are public, 51 displays relevant fines from various states across the U.S.

Table 51: Maximum Fine Policies

Colorado: Colo. Rev. Stat. 34-60-121	Maximum fine is $500 - $1,000 per violation per day. The maximum total fine for violations that do not have adverse effects on public health/welfare/resources is $10,000 regardless of the number of days of continued violation. For violations that affect public health/welfare/resources the total may exceed $10,000.
Montana: MCA 82-11-147 and 149	Minimum civil penalty is $75 per violation per day and maximum is $10,000 per violation per day, up to a maximum of $125,000 per violation. A court may grant such prohibitory and mandatory injunctions as the facts may warrant, including temporary restraining orders.
New Mexico: N.M. Stat. 70-2-31	Maximum civil penalty is $1,000 per violation per day, or $5,000 for knowing and willful violations.
North Dakota: N.D.C.C. 38-08-16 and 38-08.1-07	Maximum civil penalty is $12,500 per offense per day, or $1,000 per offense per day for failure to plug drill holes.
Wyoming: Wyo. Stat. Ann. 30-5-119	Maximum civil penalty is $5,000 per violation per day that a violation continues, or $10,000 per day for knowing and willful violations.
BLM: 43 CFR 3160	Maximum assessment is $500 per major violation per day, $250 per minor violation per day , or $1,000 per day per operator per lease. If a violation is not corrected within at least 20 days, the operator is liable for a civil penalty of up to $500 per violation per day.
Texas	*Additionally, Texas Railroad Commission Community and Outreach department reported that "the maximum penalty allowed by statute for violations of the Commission's oil and gas rules is $10,000 per violation per day."

12.4.6 Conclusions and Regulations

The Bureau of Land Management (BLM) has implemented a new risk-based strategy for enforcement, which requires updated databases for tracking high- and low-risk operations before it can be fully implemented. This should help provide clearer federal guidelines on state data collection and inspection activities, in the absence of a uniform federal regulatory scheme for oil and gas programs. We provide the text of this below:

- **Relevant State Regulation - US BLM:**

Instructions for Prioritization of Drilling Inspections Drilling Inspections

The Bureau of Land Management (BLM) goal is to conduct a drilling inspection on all wells with a downhole priority rating of high. Therefore, offices must determine a downhole inspection priority (high or low) for each well drilled. Offices must document that priority in the Application for Permit to Drill (APD) Engineering review screen in the Automated Fluid Minerals Support System (AFMSS) (screen GLB.79). The ranking of each well will require coordination between the engineers, geologists, and inspection and enforcement staff. This ranking is for the technical drilling inspection (DW) and not the environmental inspection (ES). The ranking of each well will occur in two phases. The first phase occurs during the engineering review of the APD where the engineer will identify potential issues regarding the well. The second phase is after the BLM receives the spud notice, and the operator informs the BLM of the drilling rig and contractor it is using to drill the well. At that time, the BLM will determine the priority based on the issues identified by the engineer during the APD review, and potential issues with the drilling rig or contractor drilling the well. The main consideration during the ranking process is whether an inspection is necessary to ensure compliance in an area where specific drilling operations pose a high potential risk to public health and safety, the environment, and/or other resources.

APD Review

Petroleum engineers, in coordination with geologists, will identify downhole concerns during the engineering review of the APD. The engineer must document in the "Priority Reason" section of the APD Engineering Review screen, the downhole concerns identified, and the specific operations that may need to be witnessed (surface casing cementing, blowout prevention equipment test, etc.). Following are items the engineer should consider during the review.

- New operator
- Known operational/compliance/safety problems with operator/field
- Geologic concerns
- Formations will be penetrated which have zones known to contain or which could reasonably be expected to contain concentrations of hydrogen sulfide ($H2S$) which require compliance with Onshore Order No. 6
- Well to be drilled as a wildcat and not part of an infill drilling plan
- High surface pressure anticipated (BOPE> 5M or third ram required)
- Usable water below the surface casing that will be isolated by the intermediate or production casing

- Local area concerns or other specific concerns identified during the APD review The operator addresses many of these items in the drilling plan, and the engineer evaluates these items during the APD review. Therefore, just because one or more of these items exist, does not necessarily mean the engineer must rate the well as a high-priority. However, as stated above, the engineer shall document any concerns in the "Priority Reason" section of the APD review screen. If the engineer identifies something during the APD review that a petroleum engineering technician (PET) must inspect or witness, the engineer should rate the well as a high-priority.

Otherwise, the engineer should rate the well as a low-priority until the operator provides the spud notice, at which time the engineer, in coordination with the inspection and enforcement (I&E) staff, will reevaluate the ranking. Even if the well is rated as a low-priority at the time of engineering review of the APD, the engineer will document, in the priority reason screen, any concerns that may warrant raising the well to a high-priority and/or the reason the engineer rated the well as a low-priority. With sufficient documentation in AFMSS, the engineer will not need to re-review the APD at the time of well spud.

Drilling Priority Inspection Ranking (Risk-based at time of well spud)
Final priority ranking of wells will be accomplished by the I&E staff (Supervisory or Lead PET for offices that have those positions) and the Petroleum Engineer when the field office (FO) receives notice that a well has been spud. Based on the risk factors for the drilling rig, drilling rig contractor, and the engineer's downhole concerns identified during the APD review, the FO will determine the priority and the type of inspection necessary. Following are items the FO should consider regarding the drilling rig and contractor:

- Drilling rig in the FO jurisdiction for the first time
- All drilling rigs in the FO jurisdiction for the first time will be rated as a high priority.
- History of past issues with the drilling rig/drilling contractor
- This includes any operational incidents of noncompliance (INC) issued, as well as other concerns including safety, identified during past inspections that did not result in INCs being issued such as reoccurring problems with the BOPE requiring repairs that were corrected during previous inspection/witness. Other factors include the overall condition of the rig equipment.
- Number of wells drilled by the rig since the last BLM inspection
- As a general rule, all drilling rigs should be inspected at least once every four wells drilled. In order to identify potential issues with the drilling rig or drilling rig contractor, the FOs must be able to track the drilling rigs. Ideally, this tracking system would be part of the AFMSS database, but due to many factors, that is not feasible at this time.

Therefore, the FOs must develop and maintain a drilling rig tracking system independent of AFMSS. Some FOs have already developed tracking systems, and they can continue to use those systems. For those offices that do not have a tracking system, attached is a spreadsheet that offices may use in lieu of creating their own tracking system. Based on the drilling rig/contractor factors and the downhole concerns, the FO will determine a final priority rating for the well. The FO must update the priority and the Priority Reason in the APD Engineering review screen in AFMSS (screen GLB.79) with the final priority rating. When updating the Priority Reason, the FO must leave the original remarks, and add additional remarks to document the final priority. The updated Priority Reason must also include the date of the update and the name of the person entering the update.

FOs must not base the priority rating on availability of personnel to conduct the required inspection. FOs must base the priority rating on the drilling rig/contractor factors and downhole concerns regardless of whether there are inspection resources available to conduct the inspection, and AMFSS should accurately reflect that priority.

12.5 Permitting, Baseline, and Disclosure Regulations

At the heart of violations and fines is the idea that damage and liability can be accurately and fairly assessed. However in many oil and gas developments, legal proof has been tough goal to achieve (Merrill and Schizer 2013). It rests on baseline data and full disclosure of chemicals. Liability cannot be determined if harm cannot be proven and top prove harm, most courts require independent third party laboratories to do the analysis.

As such, this section explores the literature regarding baseline disclosure issues.

12.5.1 Information Sources

(Merrill and Schizer 2013)	“The Shale Oil and Gas Revolution, Hydraulic Fracturing, and Water Contamination: A Regulatory Strategy”	"This Article proposes a strategy for regulating water contamination from fracturing. For issues that are already well understood, we would rely on best practices regulations. For issues that are unique to fracturing and are not yet well understood, we would rely on liability rules - and, specifically, a hybrid of strict liability and a regulatory compliance defense - to motivate industry to take precautions, develop risk-reducing innovations, and cooperate in the development of best practices regulations. To facilitate more accurate determinations of causation, we recommend information-forcing rules (e.g., requiring energy companies to test water quality before they begin fracturing). We also suggest other design features for the liability system, such as one-way fee shifting and provisions to ensure that defendants will not be judgment proof. To ensure that the regulatory regime draws on existing regulatory expertise and is both dynamic and tailored to local conditions, we recommend keeping the regulatory center of gravity in the states, instead of fashioning a new federal regime."
(Centner 2013)	“Oversight of shale gas production in the United States and the disclosure of toxic substances”	This article reviews the curent state of disclosure laws for oil and gas and concludes: "While balancing the secrecy of proprietary information, economic performance, injuries to humans, and environmental damages is difficult, legislators charged with promoting public welfare may be neglecting their duties by supporting nondisclosure exceptions that increase uses of toxic chemicals and sacrifice public health"
(Centner and O’Connell 2014)	“Unfinished business in the regulation of shale gas production in the United States.”	"The aim of the study is to offer state governments ideas for addressing contractual obligations of drilling operators, discerning health risks, disclosing toxic chemicals, and reporting sufficient information to detect problems and enforce regulations. The discussion suggests opportunities for state regulators to become more supportive of public health through greater oversight of shale gas extraction."

In most states, the burden of proof the burden of proof is on the harmed, as in oil and gas operators are "innocent until proven guilty". However this is not the case for Pennsylvania (the relevant regulations are reprinted below).

Companies are not required to publicly disclose the chemicals they use by federal law. They are exempt from the Emergency Planning and Community Right to Know Act (EPCRA) which requires hazardous chemicals more than 10,000 to be reported. (Centner 2013) focuses on disclosure regulations regarding chemicals and suggests that trade secrets should not trump public health.(Centner and O’Connell 2014) build further upon this point by bringing up ideas for "addressing contractual obligations of drilling operators, discerning health risks, disclosing toxic chemicals, and reporting sufficient information to detect problems and enforce regulations."

Given the social importance of disclosure regulations, this report has included relevant regulations addressing these issues of baseline data and public disclosure.

- **Relevant State - Pennsylvania:**

§ 3218. Protection of water supplies.

(a) General rule.–In addition to the requirements of subsection (c.1), a well operator who affects a public or private water supply by pollution or diminution shall restore or replace the affected supply with an alternate source of water adequate in quantity or quality for the purposes served by the supply. The department shall ensure that the quality of a restored or replaced water supply meets the standards established under the act of May 1, 1984 (P.L.206, No.43), known as the Pennsylvania Safe Drinking Water Act, or is comparable to the quality of the water supply before it was affected by the operator if that water supply exceeded those standards. The Environmental Quality Board shall promulgate regulations necessary to meet the requirements of this subsection.
(b) Pollution or diminution of water supply.–A landowner or water purveyor suffering pollution or diminution of a water supply as a result of the drilling, alteration or operation of an oil or gas well may so notify the department and request that an investigation be conducted. Within ten days of notification, the department shall investigate the claim and make a determination within 45 days following notification. If the department finds that the pollution or diminution was caused by drilling, alteration or operation activities or if it presumes the well operator responsible for pollution under subsection (c), the department shall issue orders to the well operator necessary to assure compliance with subsection (a), including orders requiring temporary replacement of a water supply where it is determined that pollution or diminution may be of limited duration. (b.1) (Reserved).
(b.2) Telephone number.–The department shall establish a single Statewide toll-free telephone number that persons may use to report cases of water contamination which may be associated with the development of oil and gas resources. The Statewide toll-free telephone number shall be provided in a conspicuous manner in the notification required under section 3211(b) (relating to well permits) and on the department's Internet website.
(b.3) Responses.–The department shall develop appropriate administrative responses to calls received on the Statewide toll-free telephone number for water contamination.
(b.4) Website.–The department shall publish, on its Internet website, lists of confirmed cases of subterranean water supply contamination that result from hydraulic fracturing.
(b.5) Facility operation qualifications.–The department shall ensure that a facility which seeks a National Pollutant Discharge Elimination System permit for the purposes of treating and discharging wastewater originating from oil and gas activities into waters of this Commonwealth is operated by a competent and qualified individual.

(c) Presumption.–Unless rebutted by a defense established in subsection (d), it shall be presumed that a well operator is responsible for pollution of a water supply if:
(1) except as set forth in paragraph (2):
(i) the water supply is within 1,000 feet of an oil or gas well; and
(ii) the pollution occurred within six months after completion of drilling or alteration of the oil or gas well; or
(2) in the case of an unconventional well:
(i) the water supply is within 2,500 feet of the unconventional vertical well bore; and
(ii) the pollution occurred within 12 months of the later of completion, drilling, stimulation or alteration of the unconventional well.
(c.1) Requirement.–If the affected water supply is within the rebuttable presumption area as provided in subsection (c) and the rebuttable presumption applies, the operator shall provide a temporary water supply if the water user is without a readily available alternative source of water. The temporary water supply provided under this subsection shall be adequate in quantity and quality for the purposes served by the supply.
(d) Defenses.–To rebut the presumption established under subsection (c), a well operator must affirmatively prove any of the following:
(1) except as set forth in paragraph (2):
(i) the pollution existed prior to the drilling or alteration activity as determined by a predrilling or prealteration survey;
(ii) the landowner or water purveyor refused to allow the operator access to conduct a predrilling or prealteration survey;
(iii) the water supply is not within 1,000 feet of the well;
(iv) the pollution occurred more than six months after completion of drilling or alteration activities; and
(v) the pollution occurred as the result of a cause other than the drilling or alteration activity; or
(2) in the case of an unconventional well:
(i) the pollution existed prior to the drilling, stimulation or alteration activity as determined by a predrilling or prealteration survey;
(ii) the landowner or water purveyor refused to allow the operator access to conduct a predrilling or prealteration survey;
(iii) the water supply is not within 2,500 feet of the unconventional vertical well bore;
(iv) the pollution occurred more than 12 months after completion of drilling or alteration activities; or
(v) the pollution occurred as the result of a cause other than the drilling or alteration activity.
(e) Independent certified laboratory.–An operator electing to preserve a defense under subsection (d)(1) or (2) shall retain an independent certified laboratory to conduct a predrilling or prealteration survey of the water supply. A copy of survey results shall be submitted to the department and the landowner or water purveyor in the manner prescribed by the department.

(e.1) Notice.–An operator of an unconventional well must provide written notice to the landowner or water purveyor indicating that the presumption established under subsection (c) may be void if the landowner or water purveyor refused to allow the operator access to conduct a predrilling or prealteration survey. Proof of written notice to the landowner or water purveyor shall be provided to the department for the operator to retain the protections under subsection (d)(2)(ii). Proof of written notice shall be presumed if provided in accordance with section 3212(a) (relating to permit objections).
(f) Other remedies preserved.–Nothing in this section shall prevent a landowner or water purveyor claiming pollution or diminution of a water supply from seeking any other remedy at law or in equity.

- **Relevant SB.4 Text**

1777.4. Well Maintenance and Cleanout History.

(a) Unless already addressed by an approved aggregation plan under subdivision (d), within 60 days of completing an operation on a well that involves emplacing fluid containing acid in the well, the operator shall submit the following information to the Division for inclusion in the well history:
(1) A description of the nature and purpose of the operation;
(2) The volume of fluid emplaced in the well in the course of the operation, including specification of the gallons per treated foot; and
(3) Calculation of the Acid Volume Threshold for the operation.

(b) Within 60 days of completing an operation on a well that involves application of pressure to the formation that exceeds formation pore pressure, the operator shall submit the following information with the Division for inclusion in the well history:
(1) A description of the nature and purpose of the operation; and
(2) The bottom-hole pressure applied to the formation; and
(3) Calculations used to determine bottom-hole pressure, if any.

(c) This section does not apply to the following operations:
(1) Well stimulation treatments regulated under Article 4 of this subchapter;
(2) Underground injection project operations regulated under Sections 1724.6 through 1724.10 or Sections 1748 through 1748.3;
(3) Drilling, redrilling, reworking, plugging, or abandonment operations permitted under Public Resources Code section 3203 or 3229; and
(4) Replacement of equipment in the well, including but not limited to packers, pumps, and tubing.

(d) Subject to approval by the Division, an operator may propose a plan for submitting aggregated information regarding a specific type of repeated operation that involves emplacing fluid containing acid in the well yet clearly does not meet the definition of a well stimulation treatment. An aggregation plan shall provide for annual submission of the aggregated volume of fluid containing acid used in an oilfield for the type of operation, a list of the wells subject to the operation during the year, and, if the operation is performed multiple times on the same well, the number of time the operation was performed on each well. An aggregation plan may be terminated at the Division's sole discretion.

(e) The Division will maintain a searchable index of submissions made under this section, and the index will be made available on the Division's public internet website. The searchable index will clearly indicate each submission for a treatment that exceeds the formation fracture gradient or emplaces acid in the well and exceeds the Acid Volume Threshold, and such submissions shall include the Division's determination that the treatment is not a well stimulation treatment and the basis for the determination.

1788. Required Public Disclosures.

(a) Except as provided in subdivision (c), within 60 days after the cessation of a well stimulation treatment, the operator shall publicly disclose all of the following information:
(1) Operator's name;
(2) API number assigned to the well by the Division;
(3) Lease name and number of the well;
(4) Location of the well, submitted as a six-digit decimal degrees, non-projected, Latitude and Longitude, in the Geographic Coordinate System (GCS) NAD83.
(5) County in which the well is located;
(6) Date that the well stimulation treatment occurred;
(7) The measured and true vertical depth of the well;
(8) Formation name and vertical depth of the top and bottom of the productive horizon where well stimulation treatment occurred; (9) The trade name, supplier, concentration, and a brief description of the intended purpose of each additive contained in the well stimulation fluids used;
(10) The total volume of base fluid used during the well stimulation treatment;
(11) Identification of whether the base fluid is water suitable for irrigation or domestic purposes, water not suitable for irrigation or domestic purposes, or a fluid other than water;
(12) The source, volume, and specific composition and disposition of all water associated with the well stimulation treatment, including all of the following:
(A) The source of the water used as a base fluid for the well stimulation treatment, including any of the following:
(i) The well or wells, if commingled, from which the water was produced or extracted;
(ii) The water supplier, if purchased from a supplier;
(iii) The point of diversion of surface water;
(B) Composition of water used as base fluid, including all of the following: total

dissolved solids; metals listed in California Code of Regulations, title 22, section 66261.24, subdivision (a)(2)(A); benzene, toluene, ethyl benzene, and xylenes; major and minor cations (including sodium, potassium, magnesium, and calcium); major and minor anions (including nitrate, chloride, sulfate, alkalinity, and bromide); and trace elements (including lithium, strontium, and boron);
(C) Specific disposition of water recovered from the well following the well stimulation treatment, including method and location of disposal and, if the recovered water is injected into an injection well, identification of the operator, field, and project number of the injection project;
(D) Composition of water recovered from the well following the well stimulation treatment, sampled after a calculated wellbore volume has been produced back but before three calculated wellbore volumes have been produced back, and then sampled a second time after 30 days of production after the first sample is taken, with both samples taken prior to being placed in a storage tank or being aggregated with fluid from other wells;
(E) Composition of water recovered from the well following the well stimulation treatment shall be determined by testing the samples taken under paragraph (D) for all of the following: appropriate indicator compound(s) for the well stimulation treatment fluid; total dissolved solids; metals listed in California Code of Regulations, title 22, section 66261.24, subdivision (a)(2)(A); benzene, toluene, ethyl benzene, and xylenes; major and minor cations (including sodium, potassium, magnesium, and calcium); major and minor anions (including nitrate, chloride, sulfate, alkalinity, and bromide); and trace elements (including lithium, strontium, and boron); radium-226, gross alpha-beta, radon 222, fluoride, iron (redox), manganese (redox), H2S (redox), nitrate+nitrite (redox), strontium, thallium, mercury, and methane;
(F) All testing results shall have a cover page briefly describing when and where sampling was done and the results of the testing;
(G) Sampling and testing conducted under subdivision (a)(12) is separate from and in addition to any sampling or testing that may be required to make hazardous waste determinations under the requirements of the Department of Toxic Substances Control;
(13) Identification of any reuse of treated or untreated water for well stimulation treatments and well stimulation treatment-related activities;
(14) The specific composition and disposition of all well stimulation treatment fluids, including waste fluids, other than water;
(15) Any radiological components or tracers injected into the well as part of the well stimulation treatment, a description of the recovery method, if any, for those components or tracers, the recovery rate, and specific disposal information for recovered components or tracers;
(16) The radioactivity of the recovered well stimulation fluids, and a brief description of the equipment and method used to determine the radioactivity;
(17) For each stage of the well stimulation treatment, the measured and true vertical depth of the location of the portion of the well subject to the well stimulation treatment and the extent of the fracturing or other modification, if any, surrounding the well induced

by the treatment;
(18) The estimated volume of well stimulation treatment fluid that has been recovered; and
(19) A complete list of the names, Chemical Abstract Service numbers, and maximum concentration, in percent by mass, of each and every chemical constituent of the well stimulation treatment fluids used. If a Chemical Abstract Service number does not exist for a chemical constituent, the operator may provide another unique identifier, if available.
(b) For hydraulic fracturing well stimulation treatments, the operator shall post the information listed in subdivision (a) to the Chemical Disclosure Registry, to the extent that the website is able to receive the information. For all well stimulation treatments, the operator shall provide all of the information listed in subdivision (a) directly to the Division on the Well Stimulation Treatment Disclosure Reporting Form. The Well Stimulation Treatment Disclosure Reporting Form is available on the Division's public internet website at `ftp://ftp.consrv.ca.gov/pub/oil/forms/Oil\%26Gas/OG110S.XLSX` The Well Stimulation Treatment Disclosure Reporting Form shall be submitted to the Division in an electronic format, directed to the email address "DisclosureWST@conservation.ca.gov". The Division will organize the information provided on Well Stimulation Treatment Disclosure Forms in a format, such as a spreadsheet, that allows the public to easily search and aggregate, to the extent practicable, each type of information disclosed.
(c) Except for the information specified in subdivision (a)(1) through (6), operators are not required to publicly disclose information found in a well record that the Division has determined is not public record, pursuant to Public Resources Code section 3234. If information listed in subdivision (a) is not publicly disclosed on this basis, then the operator shall inform the Division in writing, and provide the Division the information that is not being publicly disclosed. The Division will provide the information that is not publicly disclosed to other state agencies as needed for regulatory purposes and in accordance with a written agreement with the other state agency regarding sharing of confidential information. It is the operator's responsibility to publicly disclose the withheld information in the manner described in subdivision (b) as soon as the information becomes public record under Public Resources Code section 3234.
(d) A claim of trade secret protection for the information required to be disclosed under this section shall be handled in the manner specified under Public Resources Code section 3160, subdivision (j).
(e) Groundwater quality data reported under this section shall also be submitted to the Regional Water Board in an electronic format that follows the guidelines detailed in California Code of Regulations, title 23, chapter 30.
(f) If for any reason information specified in subdivision (a) cannot be collected within 60 days after the cessation of a well stimulation treatment, then the information shall still be publicly disclosed as soon as possible in the manner described in subdivision (b).

1789. Post-Well Stimulation Treatment Report.

(a) Within 60 days after the cessation of a well stimulation treatment, the operator shall submit a report to the Division describing:
(1) The pressures recorded during monitoring required under Section 1785(a) during the well stimulation treatment;
(2) The pressures recorded during the first 30 days of production pressure monitoring under Section 1787(d)(1);
(3) The date and time that each stage of the well stimulation treatment was performed;
(4) How the actual well stimulation treatment differs from what was anticipated in the well stimulation treatment design that was prepared under Section 1784(b);
(5) How the actual location of the well stimulation treatment differs from what was indicated in the permit application under Section 1783.1(a)(15); and
(6) A description of hazardous wastes generated during the well stimulation activities and their disposition, including copies of all hazardous waste manifests used to transport the hazardous wastes offsite to an authorized facility.
(b) If information found in a report submitted under this section is found in a well record that the Division has determined is not public record, pursuant to Public Resources Code section 3234, then the Division will provide the information to other state agencies as needed for regulatory purposes and in accordance with a written agreement with the other state agency regarding sharing of confidential information.

1783.2 Neighbor Notification, Duty to Hire Independent Third Party.

(a) The operator of any oil or gas well receiving a permit to conduct well stimulation treatment from the Division shall hire an independent third party to perform the following actions:

(1) Identify surface property owners and tenants, other than the operator of the well subject to well stimulation treatment, of legally recognized parcels of land situated within a 1500-foot radius of the wellhead receiving well stimulation treatment, or within 500 feet of the surface representation of the horizontal path of the subsurface parts of such well;
(2) Provide all surface property owners and tenants so identified, or their duly authorized agents, with neighbor notification that shall include and must be limited to both of the following:
(A) A copy of the approved well stimulation treatment permit; and
(B) A completed Well Stimulation Treatment Neighbor Notification Form (7/15 version), hereby incorporated by reference; and
(3) Compile and mail to the Division a declaration of notice pursuant to subdivision (i).
(b) Neighbor notification is not required if the independent third party determines that there are no surface property owners or tenants as described in subdivision (a)(1).
(c) A well stimulation treatment subject to the neighbor notification requirements of this section shall not commence until 30 calendar days after all required notices are provided, as defined in subdivision (e). If the independent third party has made a determination

under subdivision (b) that neighbor notification is not required, then the well stimulation treatment shall not commence until at least 72 hours after the operator provides the Division with a signed written statement from the independent third party certifying that determination.

(d) The notice required under subdivision (a)(2) may be given by any of the following means:

(1) Personal delivery;

(2) Overnight delivery by an express service carrier;

(3) Registered, certified, or express mail;

(4) Electronic mail or facsimile, but only if the person to be notified has agreed in writing prior to the notice to accept notice by electronic mail or facsimile. The prior written agreement shall contain the email address or facsimile number of the person to be notified, which address or number shall be used until otherwise instructed by the person to be notified.

(e) The notice required under this section is deemed to have been provided at the following times:

(1) If given by personal delivery, when delivered;

(2) If given by overnight delivery by an express service carrier, 2 calendar days after the notice is deposited with the carrier;

(3) If given by registered, certified or express mail, 5 calendar days after the notice is deposited in the mail;

(4) If given by electronic mail or facsimile, 2 calendar days after the notice is transmitted.

(f) Any notice that is given to surface property owners by overnight delivery by an express service carrier or by registered, certified, or express mail shall be addressed to the address of record for that person, or his/her duly authorized agent, as shown on the latest equalized assessment roll, county assessor or tax collector records. In addition, if the owner's address of record is different from the physical address of the property within the notification radius, and if that property is capable of receiving mail, a copy of the notice shall also be delivered or mailed to that property.

(g) Notice to a tenant shall not be considered deficient for lack of a named individual. Notice to any tenant can be addressed generally to "current resident," "current occupant," or such other non-specific addressee, as may be appropriate.

(h) In addition to the means set forth in subdivision (d), tenants of a residential or commercial property that has 10 or more individual units for lease may be provided notice by leaving the copy of the permit and Well Stimulation Treatment Neighbor Notification Form at each individual residential or commercial unit within the residential or commercial property between the hours of eight in the morning and six in the evening, with some person not less than 18 years of age who provides a signature acknowledging receipt of the notice. Notice given in accordance with this subdivision shall be treated as a personal delivery for purposes of determining when such notice is deemed provided under subdivision (e).

(i) The independent third party hired by the operator to provide notice under this section shall, within 5 calendar days of all required notices having been provided for a well stimulation treatment, submit to the Division in a text-searchable electronic format, directed to the email address "NeighborNotificationWST@conservation.ca.gov" a declaration of notice that provides all of the following:

(1) Identifying information for the well receiving well stimulation treatment and the operator of that well;

(2) A list of all notices provided, itemized by the County Assessor's Parcel Number for the property within the notification radius that corresponds to each notice provided;

(3) The name of each surface property owner and tenant notified, or indication that the addressee was unspecified, as allowed under subdivision (g);

(4) The specific method of providing each notice, including the physical or electronic address to which each notice was sent;

(5) The date each notice was personally delivered, deposited with an express carrier or mail service, or transmitted electronically;

(6) The date each notice is deemed to have been provided in accordance with subdivision (e); and

(7) Representative copies of the completed Well Stimulation Treatment Neighbor Notification Form that were provided.

(j) If any additional surface property owners or tenants are notified after the original declaration of notice is provided to the Division, then the independent third party shall within 5 calendar days submit to the Division a supplemental declaration of notice that contains the information listed in subdivision (i).

(k) Each independent third party hired by the operator to provide notice under this section shall retain copies of all of the following:

(1) A representative copy of the well stimulation treatment permits provided to surface property owners and tenants;

(2) Representative copies of the completed Well Stimulation Treatment Neighbor Notification Form provided to surface property owners and tenants;

(3) Documentation demonstrating that the notices required under this section were provided, including documentation from the United States Postal Service or express service carrier such as proof of payment records, return receipts, delivery confirmations, and tracking records; and

(4) Records relied upon to identify surface property owners and tenants who must receive notice under this section.

(l) Records specified for retention under subdivision (k) shall be made available to the Division promptly upon request, and shall be maintained for at least 5 years from the date that the declaration of notice required under subdivision (h) is submitted to the

Division.

1785. Monitoring During Well Stimulation Treatment Operations.

(a) The operator shall continuously monitor and record all of the following parameters during the well stimulation treatment, if applicable:

(1) Surface injection pressure;
(2) Slurry rate;
(3) Proppant concentration;
(4) Fluid rate; and
(5) All annuli pressures.

(b) The operator shall terminate the well stimulation treatment and immediately provide the collected data to the Division if any of the following occurs:

(1) A pressure change in the annulus between the tubing or casing through which well stimulation treatment fluid is conducted and the next larger tubular or casing more than 20% or greater than the calculated pressure increase due to pressure and/or temperature expansion;

(2) Pressure exceeding 90% of the API rated minimum internal yield on any casing string in communication with the well stimulation treatment, if the pressure testing under Section 1784.1(a)(1) was done at a pressure equal to 100% of the API rated minimum internal yield of the tested casing;

(3) Pressure exceeding 80% of the API rated minimum internal yield on any casing string in communication with the well stimulation treatment, if the pressure testing under Section 1784.1(a)(1) was done at a pressure equal to less than 100% of the API rated minimum internal yield of the tested casing; or

(4) The operator has reason to suspect a potential breach in the cemented casing strings, the tubing strings utilized in the well stimulation treatment operations, or the geologic or hydrologic isolation of the formation.

(c) If any of the events listed in subdivision (b) occurs, then the operator shall perform diagnostic testing on the well to determine whether a breach has occurred. Diagnostic testing shall be done as soon as is reasonably practical. The Division shall be notified when diagnostic testing is being done so that Division staff may witness the testing. All diagnostic testing results shall be immediately provided to the Division.

(d) If diagnostic testing reveals that a breach has occurred, then the operator shall immediately shut-in the well, isolate the perforated interval, and notify the Division and the Regional Water Board with all of the following information:

(1) A description of the activities leading up to the well breach.

(2) Depth interval of the well breach and methods used to determine the depth interval.
(3) An exact description of the chemical constituents of the well stimulation treatment fluid, or of the fluid that is most representative of the fluid composition in the well at the time of the well breach.
(e) The operator shall not resume operation of a well that has been shut-in under subdivision
(d) without first obtaining approval from the Division.
(f) Groundwater quality data submitted under subdivision (d) shall be in an electronic format that follows the guidelines detailed in California Code of Regulations, title 23, chapter 30.
(g) If the surface casing annulus is not open to atmospheric pressure, then the surface casing pressures shall be monitored with a gauge and pressure relief device. The maximum set pressure on the relief device shall be the lowest of the following and well stimulation treatment shall be terminated if pressures in excess of the maximum set pressure are observed in the surface casing annulus:
(1) A pressure equal to: 0.70 times 0.433 times the true vertical depth of the surface casing shoe (expressed in feet);
(2) 70% of the API rated minimum internal yield for the surface casing; or
(3) A pressure change that is 20% or greater than the calculated pressure increase due to pressure and/or temperature expansion.

- **Relevant API Standards**

American Petroleum Institute. *API HF2, Water Management Associated with Hydraulic Fracturing, First Edition/June 2010*. URL: `http://www.api.org/policy-and-issues/policy-items/hf/api\_hf2\_water\_management.aspx` (visited on 01/26/2015)

- **Relevant STRONGER Guidelines**

9.2.2. Reporting
The regulatory agency should require appropriate notification prior to, and reporting after completion of, hydraulic fracturing operations. Notification should be sufficient to allow for the presence of field staff to monitor activities. Reporting should include the identification of materials used, aggregate volumes of fracturing fluids and proppant used, and fracture pressures recorded.

State programs should contain requirements for public disclosure of information on type and volume of base fluid and additives, chemical constituents, and actual or maximum concentration of each constituent used in fracturing fluids. States are encouraged to require disclosure of such information on a publicly accessible location, such as an internet website. The state should have the authority as necessary to require the conduct or submittal of diagnostic logs or alternative methods of determining well integrity. State programs should contain mechanisms for disclosure of chemical constituents used in fracturing fluids to the state in the event of an investigation and to medical personnel on a confidential basis for diagnosis and/or treatment of exposed individuals. Where information submitted is of a confidential nature, it should be treated consistent with Section 4.2.2 of the guidelines.

13 Economic and Geologic Considerations

Oil and gas is inherently a boom or bust industry and there may be significant economic consequences for communities tying themselves to a volatile industry. As prices drop, so will royalties. The report includes literature that encourages the boom-and-bust cycle to be taken into account during the process of public policy making.

13.1 Information Sources

(Sahagun 2014)	*U.S. officials cut estimate of recoverable Monterey Shale oil by 96%*	This LA Times article looks into the overestimated resources in the Monterey Shale.
(Patzek, Male, and Marder 2013)	“Gas production in the Barnett Shale obeys a simple scaling theory”	This study looks at actual shale well decline rates and gives upper and lower bounds. "This simple model provides a surprisingly accurate description of gas extraction from 8,294 wells in the United States’ oldest shale play, the Barnett Shale. There is good agreement with the scaling theory for 2,057 horizontal wells in which production started to decline exponentially in less than 10 y. The remaining 6,237 horizontal wells in our analysis are too young for us to predict when exponential decline will set in, but the model can nevertheless be used to establish lower and upper bounds on well lifetime. Finally, we obtain upper and lower bounds on the gas that will be produced by the wells in our sample, individually and in total. The estimated ultimate recovery from our sample of 8,294 wells is between 10 and 20 trillion standard cubic feet."
(Hughes 2013)	*Drill, Baby, Drill: Can Unconventional Fuels Usher in a New Era of Energy Abundance?*	"This report provides an in-depth evaluation of the various unconventional energy resources behind the recent "energy independence" rhetoric, particularly shale gas, tight oil (shale oil), and tar sands. In particular, the shale portions of this report are based on the analysis of production data for 65,000 wells from 31 shale plays using the DI Desktop/HPDI database, which is widely used in industry and government."

(Haggerty et al. 2014)	"Long-term effects of income specialization in oil and gas extraction: The U.S. West, 1980-2011"	This study looks at the long-term effects of the boom and bust cycle. "The purpose of the study is to evaluate the relationships between oil and natural gas specialization and socioeconomic well-being during the period 1980 to 2011 in a large sample of counties within the six major oil- and gas-producing states in the interior U.S. West: Colorado, Montana, New Mexico, North Dakota, Utah, and Wyoming. ... Our findings contribute to a broader public dialogue about the consequences of resource specialization involving oil and natural gas and call into question the assumption that long-term oil and gas development confers economic advantages upon host communities."

13.2 Summary of Information Sources

These studies cover uncertainty within the geologic resource, the market cycle, and the possible social consequences resulting from these cycles. They should be taken as evidence that large-scale uncertainty is inherent in the development of shale resources.

13.3 Analysis of Information

During the process of writing this report the US EIA cut their estimate of the amount of oil contained within California by 96% (Sahagun 2014). This drastic decrease should give indication that the shale resource is not as well understood as conventional resources and policy planners should account for this uncertainty. Indeed, SB.4 was written during a context of a much larger planned development. It is useful to include to get an idea of the time-frame that active environmental impacts will have. More specifically this report points to a decline curve modeled by (Patzek, Male, and Marder 2013) and looks at the production situation of the Barnett in Texas and gives an idea of well lifetime. This report is potentially useful in estimating EUR.

A study by (Hughes 2013) stresses that the rapid declines and limited productive drilling areas could mean that the development of oil and gas from shale plays is temporary and should be seen as a short-term boom in resources rather than a dependable long-term energy supply option. Finally, a study by (Haggerty et al. 2014) explores this issue and finds that while communities will benefit in the short-term from booms, communities with long-term focus on oil and gas had negative observed income, crime-rate, and education rate effects.

14 Recommendations for Mexico

Through the analyses of diverse literature, regulatory instruments and scientific studies, this report has gathered relevant information that has shed light on the issues of concern regarding the deployment of hydraulic fracturing activities. This section of the report will present specific recommendations that can be helpful when drafting regulatory instruments in order to achieve responsible best practices for unconventional oil and gas developments.

14.1 Procedural Recommendations

Permitting is an important instrument to ensure that drilling plants meet regulatory codes while also providing information to create records that can facilitate tracking and control of hydraulic fracturing projects.

When determining the feasibility of granting a drilling permit it is important to consider the next requirements, among the many others which have been described in the text:

- Proof of financial solvency of the solicitant company.
- Liability insurance policies with amounts that can ensure sufficient liquidity to pay for potential environmental damages.
- Development of an environmental impact assessment for a specific location proposed for development. Note that it is important that the environmental impact assessment be performed by a third party that is not associated in any way to the drilling company (to avoid any potential conflict of interest). The community, or a civil society organization present in a community (government or NGO) could be awarded the funds (paid by a drilling company) to hire a third party expert to perform the environmental impact assessment. The data used for the analysis, as well as the results of the environmental impact assessment should become publicly available before drilling begins.
- Proof of prolonged participatory engagement with civil society in a region where shale could be developed (meetings, workshops, town halls, etc.). Participatory engagement includes both explanations about project development, as well as holding detailed discussions about the local benefits and impacts that could be experienced because of drilling. Ensuring that there is community support is incredibly important in order to avoid any project implementation delays.
- Establishing a baseline. Before working in a particular region it is important to develop a baseline, including descriptive statistics from census data and surveys. Collecting data from households, including information about access to basic resources, and a needs assessment is necessary to evaluate how life in a particular place is affected after the beginning of a shale development.

Once and if a drilling permit is approved it is important to make sure that detailed reports for every substantial stage of hydraulic fracturing activities conducted by the permitted companies are made publicly available. These reports should include:

- A drill completion report that contains the specific drilling data, total depth of well and results of cementing tests.
- Monthly operations reports containing detailed information regarding well status, production volume and number of days of activity.
- Well abandonment reports after the productive lifetime of the well has ended; this report should contain results from mechanical integrity tests of the well.
- Monthly reports on chemicals used (type and amount) in hydraulic fracturing.

14.2 Land Preservation Recommendations

Land clearing impacts are common effects of hydraulic fracturing activities, compensating for land clearing and its associated "edge effects" can be complicated. Nevertheless, considering offsets might be an important policy to compensate for losses by requiring a third party to quantify land clearing impacts and propose offsetting projects to promote non-overall net loss of similar ecosystems.

Aside from land clearing, accidents and spills can occur in every stage of unconventional oil and gas developments; therefore it is important to consider the next points when addressing these issues through regulation:

- Require operators to give immediate notice of any spill, fire, leak or break to the appropriate commission followed by a full description of the event and the losses derived from it. Records on spills, fires, leaks, and any other accidents should be made publicly available. Lack of compliance in both immediate notice, or delay in the release of records should result in a fine. Compliance can be established by performing random audits as has been previously suggested, and keeping an accurate data log so that the auditor can identify anomalies.
- Providing mechanisms for operators and the public to report spills and accidents through internet (e-mail) and/or telephone (call or text - SMS) access 24 hours a day, 7 days a week.
- Determining a process to assess any cleanup or remediation needs, which should be financed by the operators.
- Considering financial and/or criminal liability derived from negligence in the operations of the developments depending on the severity of the impacts.

In regards to reclamation and restoration, it is important to enact adequate regulation pertaining to the activities to be conducted by unconventional oil and gas developers once the productive lifetime of a well has ended. When enacting regulation to address this stage of hydraulic fracturing developments, the next points are worthy of consideration (including but not limited to):

- Establishing the developer's obligation to restore.
- Requiring the draft of a site restoration plan that includes milestones to be achieved towards this goal.
- Determining the provisions for removal and filling of pits and infrastructure used to contain and store produced fluids and wastes, and the removal of all drilling supplies and equipment.
- Determining the time schedule for compliance of restoration activities, and establishing sufficiently onerous fines to deter the possibility of late action and non-compliance, including the possibility of losing the right to develop hydraulic fracturing projects in the future.

14.3 Air Quality Preservation Recommendations

Hydraulic fracturing activities cause substantial emissions of volatile organic compounds (VOCs) and green house gases that affect global air resources while contributing to climate change. Methane leakage derived from unconventional oil and gas developments poses substantial stresses on the climate given the global warming potential of this compound. In addition to burdening the climate, hydraulic fracturing activities cause emissions of VOCs which can severely damage air quality for surrounding communities.

In terms of methane leakage, the next points should be considered when enacting regulation:

- Placing specific limits to methane emissions from oil and gas developments taking into consideration leakage rates.
- Establishing auditing and monitoring mechanisms to ensure compliance with these set limits.
- Ensuring that high-resolution data from monitoring methane leakage, as well as other pollutants is publicly available. Data from wireless sensor networks monitoring air quality within a worksite as well as in neighboring communities should be publicly available.
- Enacting onerous fines for non-compliance.

Moreover, the indirect carbon dioxide emissions caused by an increase in use of natural gas for electricity generation and the added energy input requirements of hydraulic fracturing activities delivered by fossil fuels indirectly affect the climate. Although this report is not meant to analyze the feasibility of a national carbon policy, it is worth mentioning that carbon tax policies or market-based mechanisms that price carbon emissions could be explored to address these indirect impacts of unconventional oil and gas developments.

In regards to toxic emissions, the main concern has to do with volatile organic compounds (VOCs). These compounds cause health impacts in the communities surrounding unconventional oil and gas developments. Addressing these impacts through regulation requires considering the incorporation of the following measures:

- Setting limits on volatile organic compound emissions derived from the findings of location specific studies that evaluate geology characteristics and particular weather patterns.
- Establishing monitoring mechanisms to ensure compliance with these set limits.
- Enacting onerous sanctions for non-compliance.
- Determining remediation mechanisms and including financial responsibility provisions for medical expenses derived from over-exposure of impacted communities caused by developer's non-compliance.
- Requiring the implementation of "green completions" to reduce emissions of VOCâĂŹs from well completions this by essentially requiring developers to capture the gas at the well head immediately after well completion instead of releasing it into the atmosphere or flaring it off.
- Ensuring that high-resolution data from monitoring VOCs publicly available. Data from wireless sensor networks monitoring air quality within a worksite as well as in neighboring communities should be publicly available.

Flaring is of particular concern as its practice causes high point source emissions and potentially represents wasted resources as well as unnecessary environmental damages. Nevertheless, this practice is preferred over venting, given that the emissions of VOCs and HAPs are reduced to 29 and 1 ton, respectively, by flaring instead of venting; but flaring of completion gases also results in the release of more than a ton of nitrogen oxides, and almost half a ton of carbon monoxide per well. As such, determining the scope of use of this practice is of significant concern. Therefore, it is important to consider the next measures, when addressing this issue:

- Establishing the use of a flaring map that compiles nightly infrared data to display gas flares associated with oil and gas production to determine the sources.[4]
- Requiring operators to submit gas capture plans as part of the permit process.
- Allowing flaring only in cases where hydrocarbons are technically impossible to collect regardless of economic feasibility issues.
- Requiring companies to pay full market value price for the gas flared, and establishing programs to direct those proceedings for the benefit of the surrounding communities.
- Tracking the amount of gas flared through audits, without relying in self-reporting mechanisms.
- Establishing sanctions for illegal flaring and making enforcement data available to the public.

14.4 Biodiversity Conservation Recommendations

Pollution, noise, infrastructure, traffic, and many other shale gas development operations pose significant impacts to ecosystems and wildlife. The next measures should be considered when addressing these impacts in order to minimize adverse effects:

- Building a baseline registry of the local ecosystems including wildlife and birdlife before the drilling permit process begins, and including this registry in the environmental impact assessment which has been detailed above.
- Developing objective studies focused on evaluating the particular impacts of ecosystems and wildlife within play areas, in order to ensure adequate information for decision-making processes regarding mitigation strategies, offsetting projects or permit denials.
- Requiring maps showing topography and wetlands as part of the drilling permit application. This is to ensure pits and wells are located away from wetlands and watercourses to minimize impacts of spills and other accidents.
- Requiring an emergency and spill response plan as part of the permit application. The standard of safety should be aimed at having resources in the area or contracts with entities that have resources in the area to be able to respond in an effective timeframe for prevention, mitigation and cleanup.
- Giving advance notice to surface owners and the general public in order to allow defense for public and natural resource interests.

[4](Skytruth is a good example of this: `http://skytruth.org/mapping-global-flaring/`)

- Requiring disclosure of all fracturing fluids compounds. This is to be able to identify the cause of the problem and its containment in a spill event.
- Systematical inspections of unconventional oil and gas developments to ensure that they are acting within the scope of their permits.
- Onerous fines and/or criminal liability for negligent or intentional non-compliance depending on the severity of the impacts caused by it.

14.5 Water Resource Management Recommendations

The massive volumetric use of water in hydraulic fracturing activities may cause scarcity issues in certain communities. The magnitude of these impacts will depend on local conditions of the shale plays, therefore, it is important to consider water source specific analyses, to determine the viability of proposed projects without compromising availability for human consumption. Once and if projects are deemed feasible, requiring monthly water usage reports, and subjecting projects to auditing can be essential tools to ensure sustainable consumption of this resource.

The use of this resource in hydraulic fracturing activities renders large volumes of produced water that contain toxic and hazardous materials. This is the main vehicle for societal harm in unconventional oil and gas developments, and as such, management and disposal of this water is of special importance when drafting regulation. In addition, faulty well construction can cause migration and subsurface contamination therefore promoting proper well construction should be deemed a priority. The next measures should be considered when addressing these issues:

In terms of water quality:

- Developing a baseline for water quality in regional water bodies as well as nearby communities before permitting begins.
- Providing mechanisms to allow surface property owners to request water quality testing on any water well or surface water.
- Requiring the company to perform regular water quality monitoring both in regional water bodies as well as nearby communities.
- Requiring water quality testing before and after well-stimulation treatment.
- Providing free and open access data to the public.
- Requiring restoration or replacement of any water supply affected by well operators. If disputes arise regarding the cause of supply affectation, the burden of proof should fall on the well operators.

In terms of well integrity:

- Developing casing and cementing codes in order to promote best practices to prevent subsurface contamination.
- Requiring pressure testing of wells before commencing well stimulation treatments; following standards developed to ensure the tests simulate real pressure conditions.
- Providing for a period of cement evaluation after placement and before well stimulation treatment; following standards developed to ensure that the quality of the cement is sufficient to provide geologic and hydrologic isolation of the oil and gas formation during and after well stimulation treatment.
- Requiring monitoring of each well that has had well stimulation treatment to prevent and remedy any potential breaches.
- Determining testing schedules for wells undertaking well stimulation treatment.
- Providing for the installation of pressure relief devices, and for the report of any pressure release from these devices.

In terms of produced water management:

- Requiring the use methods of separation of hydrocarbons from water; these methods should remove total suspended solids, and should be required regardless of the end fate of the produced water.
- Requiring the proposal and justification of the selected management method of produced water, providing for an extensive analysis of the feasibility and impacts of every other method available in order to ensure that cost is not the only factor considered for the decision.
- If disposal is to be done by injection, a permit application containing studies of the characteristics of the well, fluid and casing should be required. This as part of a statement of purpose of the project including a map showing injection facilities, pressure and rate of injection, monitoring method to be utilized, method of injection, list of protection measures, treatment of water to be injected, source and analysis of injection liquid, and location and depth of each water-source well. Moreover, requirements of monitoring for seismic activity derived from injection should be put in place in order to evaluate any potential impacts caused by earthquakes of relevant magnitude.
- If reuse for hydraulic fracturing is selected, requirements of filtering and diluting water should be explored, this to prevent chemical interference between produced water and new fracturing fluids.
- If reuse for non-oil or gas uses is selected, reverse osmosis or flash distillation should be required. Treatment through Public Owned Treatment Works

(POTW) has not been successful to fully treat produced water and therefore its not recommended as a viable method.

Auditing and establishing onerous and/or criminal liability for negligent or intentional violations in these regards, is of supreme importance to ensure water resource protection and remediation.

14.6 Infrastructure Integrity Recommendations

Just as wells can fail, so can infrastructure, pits, pipelines and tanks. These failures can derive in major spills than can cause severe impacts to water resources, ecosystems, wildlife and surrounding communities. Therefore infrastructure integrity should be addressed to ensure best practices and reduce impacts. The next measures are recommended when addressing infrastructure integrity through regulation:

- Requiring the submission of spill contingency plans.
- Requiring approval of pits, tanks and containers that are to be used to store drill cuttings, muds, and fluids to ensure they have the proper size and characteristics.
- Developing drilling mud pits standards to prevent groundwater contamination. Drilling mud pits should be prohibited if it is determined that they may cause wastes.
- Developing tank standards to ensure they are constructed to prevent corrosion, and equipped with secondary containment systems and leak detection devices.

14.7 Naturally Occurring Radioactive Materials Recommendations

Geologic formations that contain oil and gas deposits also contain naturally occurring radionuclides; therefore radioactive wastes may be created through hydraulic fracturing activities. The next measures are recommended when addressing naturally occurring radioactive materials in shale plays:

- Conducting studies to determine the radioactive levels of shale deposits.
- Providing for worker safety measures through protective equipment.
- Adding radium to spill contingency protocols to ensure cleanups are adequately characterized.
- Surveying infrastructure for NORM prior to removal and closure during restoration activities.
- Determine management and disposal measures.

14.8 Solid Waste Disposal Recommendations

Most of the solid waste consists of drill cuttings. There are also hazardous wastes associated with hydraulic fracturing activities but its volumes are highly dependent on depth and geology of the formations. The following points should be considered when addressing solid waste disposal.

- Determining which hydraulic fracturing solid wastes will be categorized as hazardous. The U.S. exempts waste coming from down-hole that would have otherwise been generated by contact with the oil and gas production stream during the removal of produced water or other contaminants from the products. However, this exception has been controversial. Thus, we recommend that wastes be categorized according to their true objective harm, and not given exceptions due to industry origin.

- Providing for waste sampling procedures to be conducted by operators to determine which generated wastes are hazardous and determining sanctions for negligent or intentional categorizing errors.

- Establishing hazardous waste management methods, and providing for sanctions for improper management.

- Promoting source reduction, recycling, treatment and proper disposal of non-hazardous waste.

14.9 Enforcement

Violations in hydraulic fracturing developments can result in devastating impacts to the environment, and to the health and safety of workers and surrounding communities. A strong enforcement agenda should be pursued in order to deter unwanted activities, and as such, the next points should be considered when determining enforcement measures in order to promote responsible best practices in the unconventional oil and gas development industry:

- Considering the creation of a new independent and transparent agency to oversee the shale gas industry, and ensuring its presence in every state where there are shale plays. If this agency is developed, it is important to include in it representatives of the community, the academia and non-governmental organizations.

- Developing a formula to assign penalty amounts considering impacts, intent, remediation costs, violator's profits and violator's history. Penalties should be proportional both the gravity of the penalty as well as to the violator's history. Efforts of cooperation by the violators can be accounted by reducing the total amount of the penalty to promote collaboration.

- Appointing sufficient inspectors to supervise and audit the practices of unconventional oil and gas developers. The generally recognized number per well needed to conduct sufficient yearly inspections is approximately 1 inspector per 1000 wells, but in order to advance sustainability through enforcement it is important to consider increasing this number.
- Establishing a public record to document every inspection.
- Providing for shutdown of operations until violations are corrected.
- Establishing mechanisms to allow reports of violations by the public.
- Audits, inspections, and fines should all be in the public domain.

14.10 Community Engagement, and Disclosure of Information Recommendations

Public engagement is crucial in the path towards sustainable shale development, as such engagement promotes better decision-making, stimulates community trust, and ultimately reduces negative impacts by increasing accountability, which in turn deters negligent practices by act or omission. A key requirement for successful community engagement is the ability to disclose to the public all the relevant information available regarding baseline data before hydraulic fracturing activities take place, permitting processes, and all the operational impacts data gathered throughout the lifetime of shale resource exploitation projects. As such, it is important to consider the next points, when addressing community engagement and data disclosure through regulation:

- Promoting proactive notification of project proposals ensuring adequate inclusion and reach through every possible channel, including leaflet drops, social media, displays, and door knocking.
- Allowing a period for information provision during which face-to-face meetings are held where operators and experts showcase interactive and visual exhibits to bring issues to life and make them tangible.
- Providing for printed materials in the language of local people explaining the issues regarding unconventional oil and gas developments.
- Ensuring the public has a chance to be involved in shaping plans, through a mixture of participation channels in which they can give opinions and interact (online, written, face-to-face meetings, etc).
- Promoting community involvement once exploration starts, including management of community benefits by local people.
- Publishing the contract and copy of the protocols and rules the operators must follow.

- Requiring operators to demonstrate commitment to work with the local community to organize logistics in order to minimize disruption during operations.
- Requiring companies to report data associated with all their operational impacts, including land clearing, water use, emissions, vehicle management, noise, light, and waste management. This data should be showcased through a website using clear quantitative metrics, on a play-by-play basis.
- Requiring operators to disclose all the chemicals used in their fracking processes.
- Disclosing all the information regarding violations, incidents, and enforcement measures.
- Creating avenues, such as providing phone numbers, for community members to call or text if they feel they are being left out of the planning process, or to voice any concerns regarding the project. All phone calls, text messages, or ways of communicating concerns will be public domain and dutifully recorded.

15 Conclusions

The benefits of hydraulic fracturing must always be weighed against the harms it causes to communities and the environment. The fact that hydraulic fracturing is still a fairly young technology leaves much room for research in terms of impacts and remediation; therefore, policy efforts should promote research and development to advance towards sustainable practices and to determine the geologic particularities of Mexican plays and the social and ecological characteristics of its surroundings.

Transparency in the processes and dynamism of the regulatory framework are crucial to keep up with the fast growth pace of this industry and to ensure public preparedness for its activities. If policy efforts are directed towards preventing and restoring all potential associated impacts, hydraulic fracturing can give high returns at low environmental and societal costs, but if not carefully addressed the results may be devastating and the costs too high to bear.

Therefore, as Mexico moves forward with the exploitation of its unconventional resources, it is of utmost importance to learn from the mistakes made in the U.S., which occurred mainly due to the unpreparedness of the regulators. Mexico has a privileged opportunity to apply the lessons derived from the U.S. experience, which have been showcased throughout this report, without internalizing the impacts that developed through this learning process.

16 Appendix I. Chemical Database

We have included MSDS sheets for all the attached chemicals all sourced from Henry A. Waxman, Edward J. Markey, and Diana DeGette (2011). "Chemicals used in hydraulic fracturing." In: *United States House of Representatives Committee on Energy and Commerce Minority Staff.*

CASRN	Chemical Name	MSD Sheet Available for CAS Number
120086-58-0	(13Z)-N,N-bis(2-hydroxyethyl)-N-methyldocos-13-en-1-aminium chloride	No
123-73-9	(E)-Crotonaldehyde	Yes
2235-43-0	[Nitrilotris(methylene)]tris-phosphonic acid pentasodium salt	Yes
65322-65-8	1-(1-Naphthylmethyl)quinolinium chloride	Yes
68155-37-3	1-(Alkyl* amino)-3-aminopropane *(42%C12, 26%C18, 15%C14, 8%C16, 5%C10, 4%C8)	Yes
68909-18-2	1-(Phenylmethyl)pyridinium Et Me derivs., chlorides	Yes
20324-33-8	1-[2-(2-Methoxy-1-methylethoxy)-1-methylethoxy]-2-propanol	Yes
78-96-6	1-Amino-2-propanol	Yes
15619-48-4	1-Benzylquinolinium chloride	Yes
71-36-3	1-Butanol	Yes
112-30-1	1-Decanol	Yes
2687-96-9	1-Dodecyl-2-pyrrolidinone	Yes
3452-07-1	1-Eicosene	Yes
629-73-2	1-Hexadecene	Yes
111-27-3	1-Hexanol	Yes
68909-68-7	1-Hexanol, 2-ethyl-, manuf. of, by products from, distn. residues	No
107-98-2	1-Methoxy-2-propanol	Yes
2190-04-7	1-Octadecanamine, acetate (1:1)	Yes
124-28-7	1-Octadecanamine, N,N-dimethyl-	Yes
112-88-9	1-Octadecene	Yes
111-87-5	1-Octanol	Yes
71-41-0	1-Pentanol	Yes
61789-39-7	1-Propanaminium, 3-amino-N-(carboxymethyl)-N,N-dimethyl-, N-coco acyl derivs., chlorides, sodium salts	Yes

61789-40-0	1-Propanaminium, 3-amino-N-(carboxymethyl)-N,N-dimethyl-, N-coco acyl derivs., inner salts	Yes
68139-30-0	1-Propanaminium, N-(3-aminopropyl)-2-hydroxy-N,N-dimethyl-3-sulfo-, N-coco acyl derivs., inner salts	Yes
149879-98-1	1-Propanaminium, N-(carboxymethyl)-N,N-dimethyl-3-[[(13Z)-1-oxo-13-docosen-1-yl]amino]-,	No
5284-66-2	1-Propanesulfonic acid	Yes
71-23-8	1-Propanol	Yes
23519-77-9	1-Propanol, zirconium(4+) salt	Yes
115-07-1	1-Propene	Yes
1120-36-1	1-Tetradecene	Yes
112-70-9	1-Tridecanol	Yes
112-42-5	1-Undecanol	Yes
2634-33-5	1,2-Benzisothiazolin-3-one	Yes
35691-65-7	1,2-Dibromo-2,4-dicyanobutane	Yes
95-47-6	1,2-Dimethylbenzene	Yes
138879-94-4	1,2-Ethanediaminium, N, N’-bis[2-[bis(2-hydroxyethyl)methylammonio]ethyl]-N,N’bis(2-hydroxyethyl)-N,N’-din	Yes
57-55-6	1,2-Propanediol	Yes
57-55-6	1,2-Propanediol	Yes
75-56-9	1,2-Propylene oxide	Yes
87-61-6	1,2,3-Trichlorobenzene	Yes
526-73-8	1,2,3-Trimethylbenzene	Yes
120-82-1	1,2,4-Trichlorobenzene	Yes
95-63-6	1,2,4-Trimethylbenzene	Yes
95-63-6	1,2,4-Trimethylbenzene	Yes
4719-04-4	1,3,5-Triazine-1,3,5(2H,4H,6H)-triethanol	Yes
108-67-8	1,3,5-Trimethylbenzene	Yes
108-67-8	1,3,5-Trimethylbenzene	Yes
123-91-1	1,4-Dioxane	Yes
9051-89-2	1,4-Dioxane-2,5-dione, 3,6-dimethyl-, (3R,6R)-, polymer with (3S,6S)-3,6-dimethyl-1,4-dioxane-2,5-dione and (3R,6S)-rel-3,6-dimethyl-1,4-dioxane-2,5-dione	No
124-09-4	1,6-Hexanediamine	Yes
6055-52-3	1,6-Hexanediamine dihydrochloride	No
68442-97-7	1H-Imidazole-1-ethanamine, 4,5-dihydro-, 2-nortall-oil alkyl derivs.	Yes
112-34-5	2-(2-Butoxyethoxy)ethanol	Yes

111-90-0	2-(2-Ethoxyethoxy)ethanol	Yes
112-15-2	2-(2-Ethoxyethoxy)ethyl acetate	Yes
102-81-8	2-(Dibutylamino)ethanol	Yes
34375-28-5	2-(Hydroxymethylamino)ethanol	Yes
21564-17-0	2-(Thiocyanomethylthio)benzothiazole	Yes
9002-93-1	2-[4-(1,1,3,3-tetramethylbutyl)phenoxy]ethanol	Yes
NA	2-Acrylamide - 2-propanesulfonic acid and N,N-dimethylacrylamide copolymer	No
15214-89-8	2-Acrylamido-2-methyl-1-propanesulfonic acid	Yes
124-68-5	2-Amino-2-methylpropan-1-ol	Yes
2002-24-6	2-Aminoethanol hydrochloride	Yes
52-51-7	2-Bromo-2-nitropropane-1,3-diol	Yes
1113-55-9	2-Bromo-3-nitrilopropionamide	Yes
96-29-7	2-Butanone oxime	Yes
143106-84-7	2-Butanone, 4-[[[(1R,4aS,10aR)-1,2,3,4,4a,9,10,10a-octahydro-1,4a-dimethyl-7-(1-methylethyl)-1-phena hydrochloride (1:1)	Yes
68442-77-3	2-Butenediamide, (2E)-, N,N'-bis[2-(4,5-dihydro-2-nortall-oil alkyl-1H-imidazol-1-yl)ethyl] derivs.	No
111-76-2	2-Butoxyethanol	Yes
110-80-5	2-Ethoxyethanol	Yes
104-76-7	2-Ethyl-1-hexanol	Yes
645-62-5	2-Ethyl-2-hexenal	Yes
5444-75-7	2-Ethylhexyl benzoate	Yes
818-61-1	2-Hydroxyethyl acrylate	Yes
13427-63-9	2-Hydroxyethylammonium hydrogen sulphite	No
60-24-2	2-Mercaptoethanol	Yes
109-86-4	2-Methoxyethanol	Yes
78-83-1	2-Methyl-1-propanol	Yes
107-41-5	2-Methyl-2,4-pentanediol	Yes
115-19-5	2-Methyl-3-butyn-2-ol	Yes
2682-20-4	2-Methyl-3(2H)-isothiazolone	Yes
78-78-4	2-Methylbutane	Yes
91-57-6	2-Methylnaphthalene	Yes
95-48-7	2-Methylphenol	Yes
79-31-2	2-Methylpropanoic acid	Yes
109-06-8	2-Methylpyridine	Yes

62763-89-7	2-Methylquinoline hydrochloride	No
37971-36-1	2-Phosphono-1,2,4-butanetricarboxylic acid	Yes
93858-78-7	2-Phosphonobutane-1,2,4-tricarboxylic acid, potassium salt (1:x)	No
555-31-7	2-Propanol, aluminum salt	Yes
26062-79-3	2-Propen-1-aminium, N,N-dimethyl-N-2-propenyl-, chloride, homopolymer	Yes
13533-05-6	2-Propenoic acid, 2-(2-hydroxyethoxy)ethyl ester	Yes
113221-69-5	2-Propenoic acid, ethyl ester, polymer with ethenyl acetate and 2,5-furandione, hydrolyzed	Yes
111560-38-4	2-Propenoic acid, ethyl ester, polymer with ethenyl acetate and 2,5-furandione, hydrolyzed, sodium salt	Yes
9003-04-7	2-Propenoic acid, homopolymer, sodium salt	Yes
9003-06-9	2-Propenoic acid, polymer with 2-propenamide	Yes
25987-30-8	2-Propenoic acid, polymer with 2-propenamide, sodium salt	Yes
37350-42-8	2-Propenoic acid, sodium salt (1:1), polymer with sodium 2-methyl-2-((1-oxo-2-propen-1-yl)amino)-1-propanesulfonate (1:1)	No
151006-66-5	2-Propenoic acid, telomer with sodium 4-ethenylbenzenesulfonate (1:1), sodium 2-methyl-2-[(1-oxo-2-propen-1-yl)amino]-1-propanesulfonate (1:1) and sodium sulfite (1:1), sodium salt	Yes
71050-62-9	2-Propenoic, polymer with sodium phosphinate	Yes
10222-01-2	2,2-Dibromo-3-nitrilopropionamide	Yes
73003-80-2	2,2-Dibromopropanediamide	Yes
27776-21-2	2,2'-(Azobis(1-methylethylidene))bis(4,5-dihydro-1H-imidazole)dihydrochloride	Yes
10213-78-2	2,2'-(Octadecylimino)diethanol	Yes
929-59-9	2,2'-[Ethane-1,2-diylbis(oxy)]diethanamine	Yes
9003-11-6	2,2'-[propane-1,2-diylbis(oxy)]diethanol	Yes
25085-99-8	2,2'-[propane-2,2-diylbis(4,1-phenyleneoxymethylene)]dioxirane	Yes
105-67-9	2,4-Dimethylphenol	Yes

24634-61-5	2,4-Hexadienoic acid, potassium salt, (2E,4E)-	Yes
87-65-0	2,6-Dichlorophenol	Yes
915-67-3	2,7-Naphthalenedisulfonic acid, 3-hydroxy-4-[2-(4-sulfo-1-naphthalenyl) diazenyl] -, sodium salt (1:3)	Yes
503-74-2	3-Methylbutanoic acid	Yes
108-39-4	3-Methylphenol	Yes
104-55-2	3-Phenylprop-2-enal	Yes
75673-43-7	3,4,4-Trimethyloxazolidine	Yes
51229-78-8	3,5,7-Triazatricyclo(3.3.1.1(superscript 3,7))decane, 1-(3-chloro-2-propenyl)-, chloride, (Z)-	Yes
5392-40-5	3,7-Dimethyl-2,6-octadienal	Yes
12068-08-5	4-(Dodecan-6-yl)benzenesulfonic acid - morpholine (1:1)	Yes
5877-42-9	4-Ethyloct-1-yn-3-ol	Yes
121-33-5	4-Hydroxy-3-methoxybenzaldehyde	Yes
122-91-8	4-Methoxybenzyl formate	Yes
150-76-5	4-Methoxyphenol	Yes
108-11-2	4-Methyl-2-pentanol	Yes
108-10-1	4-Methyl-2-pentanone	Yes
106-44-5	4-Methylphenol	Yes
104-40-5	4-Nonylphenol	Yes
51200-87-4	4,4-Dimethyloxazolidine	Yes
26172-55-4	5-Chloro-2-methyl-3(2H)-isothiazolone	Yes
106-22-9	6-Octen-1-ol, 3,7-dimethyl-	Yes
57-97-6	7,12-Dimethylbenz(a)anthracene	Yes
75-07-0	Acetaldehyde	Yes
64-19-7	Acetic acid	Yes
64-19-7	Acetic acid	Yes
25213-24-5	Acetic acid ethenyl ester, polymer with ethenol	Yes
90438-79-2	Acetic acid, C6-8-branched alkyl esters	Yes
68442-62-6	Acetic acid, hydroxy-, reaction products with triethanolamine	No
5421-46-5	Acetic acid, mercapto-, monoammonium salt	Yes
108-24-7	Acetic anhydride	Yes
67-64-1	Acetone	Yes
67-64-1	Acetone	Yes

7327-60-8	Acetonitrile, 2,2',2"-nitrilotris-	Yes
98-86-2	Acetophenone	Yes
98-86-2	Acetophenone	Yes
77-89-4	Acetyltriethyl citrate	Yes
107-02-8	Acrolein	Yes
79-06-1	Acrylamide	Yes
38193-60-1	Acrylamide-sodium-2-acrylamido-2-methlypropane sulfonate copolymer	Yes
25085-02-3	Acrylamide/ sodium acrylate copolymer	Yes
79-10-7	Acrylic acid	Yes
110224-99-2	Acrylic acid, with sodium-2-acrylamido-2-methyl-1-propanesulfonate and sodium phosphinate	Yes
107-13-1	Acrylonitrile	Yes
67254-71-1	Alcohols, C10-12, ethoxylated	No
68526-86-3	Alcohols, C11-14-iso-, C13-rich	Yes
228414-35-5	Alcohols, C11-14-iso-, C13-rich, butoxylated ethoxylated	No
78330-21-9	Alcohols, C11-14-iso-, C13-rich, ethoxylated	Yes
126950-60-5	Alcohols, C12-14-secondary	Yes
84133-50-6	Alcohols, C12-14-secondary, ethoxylated	Yes
78330-19-5	Alcohols, C7-9-iso-, C8-rich, ethoxylated	No
68603-25-8	Alcohols, C8-10, ethoxylated propoxylated	Yes
78330-20-8	Alcohols, C9-11-iso-, C10-rich, ethoxylated	Yes
309-00-2	Aldrin	Yes
93924-07-3	Alkanes, C10-14	Yes
90622-52-9	Alkanes, C10-16-branched and linear	No
68551-19-9	Alkanes, C12-14-iso-	Yes
68551-20-2	Alkanes, C13-16-iso-	Yes
64743-02-8	Alkenes, C>10 .alpha.-	Yes
68411-00-7	Alkenes, C>8	Yes
68607-07-8	Alkenes, C24-25 alpha-, polymers with maleic anhydride, docosyl esters	No
71011-24-0	Alkyl quaternary ammonium with bentonite	Yes

85409-23-0	Alkyl* dimethyl ethylbenzyl ammonium chloride *(50%C12, 30%C14, 17%C16, 3%C18)	Yes
42615-29-2	Alkylbenzenesulfonate, linear	Yes
1302-62-1	Almandite and pyrope garnet	Yes
60828-78-6	alpha-[3.5-dimethyl-1-(2-methylpropyl)hexyl]-omega-hydroxy-poly(oxy-1,2-ethandiyl)	Yes
9000-90-2	alpha-Amylase	Yes
98-55-5	Alpha-Terpineol	Yes
1302-42-7	Aluminate (AlO21-), sodium	Yes
7429-90-5	Aluminum	Yes
7429-90-5	Aluminum	Yes
12042-68-1	Aluminum calcium oxide (Al2CaO4)	Yes
7446-70-0	Aluminum chloride	Yes
1327-41-9	Aluminum chloride, basic	Yes
1344-28-1	Aluminum oxide	Yes
12068-56-3	Aluminum oxide silicate	No
12141-46-7	Aluminum silicate	Yes
10043-01-3	Aluminum sulfate	Yes
68155-07-7	Amides, C8-18 and C18-unsatd., N,N-bis(hydroxyethyl)	Yes
68140-01-2	Amides, coco, N-[3-(dimethylamino)propyl]	Yes
70851-07-9	Amides, coco, N-[3-(dimethylamino)propyl], alkylation products with chloroacetic acid, sodium salts	Yes
68155-09-9	Amides, coco, N-[3-(dimethylamino)propyl], N-oxides	Yes
68876-82-4	Amides, from C16-22 fatty acids and diethylenetriamine	Yes
68155-20-4	Amides, tall-oil fatty, N,N-bis(hydroxyethyl)	Yes
68647-77-8	Amides, tallow, N-[3-(dimethylamino)propyl],N-oxides	No
68155-39-5	Amines, C14-18; C16-18-unsaturated, alkyl, ethoxylated	Yes
68037-94-5	Amines, C8-18 and C18-unsatd. alkyl	Yes
61788-46-3	Amines, coco alkyl	Yes
61790-57-6	Amines, coco alkyl, acetates	Yes
61788-93-0	Amines, coco alkyldimethyl	Yes

61790-59-8	Amines, hydrogenated tallow alkyl, acetates	Yes
68966-36-9	Amines, polyethylenepoly-, ethoxylated, phosphonomethylated	No
68603-67-8	Amines, polyethylenepoly-, reaction products with benzyl chloride	No
61790-33-8	Amines, tallow alkyl	Yes
61791-26-2	Amines, tallow alkyl, ethoxylated	Yes
68551-33-7	Amines, tallow alkyl, ethoxylated, acetates (salts)	No
68308-48-5	Amines, tallow alkyl, ethoxylated, phosphates	Yes
6419-19-8	Aminotrimethylene phosphonic acid	Yes
7664-41-7	Ammonia	Yes
7664-41-7	Ammonia	Yes
32612-48-9	Ammonium (lauryloxypolyethoxy)ethyl sulfate	Yes
631-61-8	Ammonium acetate	Yes
10604-69-0	Ammonium acrylate	No
26100-47-0	Ammonium acrylate-acrylamide polymer	Yes
7803-63-6	Ammonium bisulfate	Yes
10192-30-0	Ammonium bisulfite	Yes
12125-02-9	Ammonium chloride	Yes
7632-50-0	Ammonium citrate (1:1)	Yes
3012-65-5	Ammonium citrate (2:1)	Yes
2235-54-3	Ammonium dodecyl sulfate	Yes
12125-01-8	Ammonium fluoride	Yes
1066-33-7	Ammonium hydrogen carbonate	Yes
1341-49-7	Ammonium hydrogen difluoride	Yes
13446-12-3	Ammonium hydrogen phosphonate	No
1336-21-6	Ammonium hydroxide	Yes
8061-53-8	Ammonium ligninsulfonate	Yes
6484-52-2	Ammonium nitrate	Yes
7722-76-1	Ammonium phosphate	Yes
7783-20-2	Ammonium sulfate	Yes
99439-28-8	Amorphous silica	Yes
104-46-1	Anethole	Yes
62-53-3	Aniline	Yes
7440-36-0	Antimony	Yes
1314-60-9	Antimony pentoxide	Yes

10025-91-9	Antimony trichloride	Yes
1309-64-4	Antimony trioxide	Yes
12672-29-6	Aroclor 1248	Yes
7440-38-2	Arsenic	Yes
7440-38-2	Arsenic	Yes
68131-74-8	Ashes, residues	Yes
68201-32-1	Asphalt, sulfonated, sodium salt	Yes
12174-11-7	Attapulgite	Yes
31974-35-3	Aziridine, polymer with 2-methyloxirane	Yes
7440-39-3	Barium	Yes
7727-43-7	Barium sulfate	Yes
1318-16-7	Bauxite	Yes
1302-78-9	Bentonite	Yes
121888-68-4	Bentonite, benzyl(hydrogenated tallow alkyl) dimethylammonium stearate complex	Yes
80-08-0	Benzamine, 4,4'-sulfonylbis-	Yes
71-43-2	Benzene	Yes
71-43-2	Benzene	Yes
98-82-8	Benzene, (1-methylethyl)-	Yes
611-14-3	Benzene, 1-ethyl-2-methyl-	Yes
119345-03-8	Benzene, 1,1'-oxybis-, tetrapropylene derivs., sulfonated	Yes
119345-04-9	Benzene, 1,1'-oxybis-, tetrapropylene derivs., sulfonated, sodium salts	Yes
68648-87-3	Benzene, C10-16-alkyl derivs.	Yes
9003-55-8	Benzene, ethenyl-, polymer with 1,3-butadiene	Yes
74153-51-8	Benzenemethanaminium, N,N-dimethyl-N-(2-((1-oxo-2-propen-1-yl)oxy)ethyl)-, chloride (1:1), polymer with 2-propenamide	No
98-11-3	Benzenesulfonic acid	Yes
37953-05-2	Benzenesulfonic acid, (1-methylethyl)-,	Yes
37475-88-0	Benzenesulfonic acid, (1-methylethyl)-, ammonium salt	Yes
28348-53-0	Benzenesulfonic acid, (1-methylethyl)-, sodium salt	Yes
68584-22-5	Benzenesulfonic acid, C10-16-alkyl derivs.	Yes

255043-08-4	Benzenesulfonic acid, C10-16-alkyl derivs., compds. with cyclohexylamine	No
68584-27-0	Benzenesulfonic acid, C10-16-alkyl derivs., potassium salts	Yes
90218-35-2	Benzenesulfonic acid, dodecyl-, branched, compds. with 2-propanamine	No
26264-06-2	Benzenesulfonic acid, dodecyl-, calcium salt	Yes
68648-81-7	Benzenesulfonic acid, mono-C10-16 alkyl derivs., compds. with 2-propanamine	No
50-32-8	Benzo(a)pyrene	Yes
205-99-2	Benzo(b)fluoranthene	Yes
191-24-2	Benzo(g,h,i)perylene	Yes
207-08-9	Benzo(k)fluoranthene	Yes
65-85-0	Benzoic acid	Yes
100-51-6	Benzyl alcohol	Yes
100-44-7	Benzyl chloride	Yes
139-07-1	Benzyldimethyldodecylammonium chloride	Yes
122-18-9	Benzylhexadecyldimethylammonium chloride	Yes
7440-41-7	Beryllium	Yes
319-85-7	beta-1,2,3,4,5,6-Hexachlorocyclohexane	Yes
68425-61-6	Bis(1-methylethyl)naphthalenesulfonic acid, cyclohexylamine salt	Yes
111-44-4	Bis(2-chloroethyl) ether	Yes
111-44-4	Bis(2-chloroethyl) ether	Yes
80-05-7	Bisphenol A	Yes
65996-69-2	Blast furnace slag	Yes
1303-96-4	Borax	Yes
10043-35-3	Boric acid	Yes
1303-86-2	Boric oxide	Yes
7440-42-8	Boron	Yes
11128-29-3	Boron potassium oxide	Yes
1330-43-4	Boron sodium oxide	Yes
12179-04-3	Boron sodium oxide pentahydrate	Yes
24959-67-9	Bromide (-1)	No
75-27-4	Bromodichloromethane	Yes
75-25-2	Bromoform	Yes
106-97-8	Butane	Yes

2373-38-8	Butanedioic acid, sulfo-, 1,4-bis(1,3-dimethylbutyl) ester, sodium salt	Yes
2673-22-5	Butanedioic acid, sulfo-, 1,4-ditridecyl ester, sodium salt	Yes
107-92-6	Butanoic acid	Yes
2426-08-6	Butyl glycidyl ether	Yes
138-22-7	Butyl lactate	Yes
104-51-8	Butylbenzene	Yes
3734-67-6	C.I. Acid red 1	Yes
6625-46-3	C.I. Acid violet 12, disodium salt	Yes
6410-41-9	C.I. Pigment Red 5	Yes
4477-79-6	C.I. Solvent Red 26	Yes
70592-80-2	C10-16-Alkyldimethylamines oxides	Yes
68002-97-1	C10-C16 ethoxylated alcohol	Yes
68131-40-8	C11-15-Secondary alcohols ethoxylated	Yes
73138-27-9	C12-14 tert-alkyl ethoxylated amines	Yes
7440-43-9	Cadmium	Yes
10045-97-3	Caesium 137	Yes
66402-68-4	Calcined bauxite	Yes
7440-70-2	Calcium	Yes
12042-78-3	Calcium aluminate	Yes
7789-41-5	Calcium bromide	Yes
10043-52-4	Calcium chloride	Yes
10035-04-8	Calcium dichloride dihydrate	Yes
7789-75-5	Calcium fluoride	Yes
1305-62-0	Calcium hydroxide	Yes
7778-54-3	Calcium hypochlorite	Yes
58398-71-3	Calcium magnesium hydroxide oxide	Yes
1305-78-8	Calcium oxide	Yes
1305-79-9	Calcium peroxide	Yes
7778-18-9	Calcium sulfate	Yes
10101-41-4	Calcium sulfate dihydrate	Yes
76-22-2	Camphor	Yes
1333-86-4	Carbon black	Yes
124-38-9	Carbon dioxide	Yes
124-38-9	Carbon dioxide	Yes
75-15-0	Carbon disulfide	Yes
471-34-1	Carbonic acid calcium salt (1:1)	Yes
584-08-7	Carbonic acid, dipotassium salt	Yes
39346-76-4	Carboxymethyl guar gum, sodium salt	No

61791-12-6	Castor oil, ethoxylated	Yes
8000-27-9	Cedarwood oil	Yes
9005-81-6	Cellophane	Yes
9012-54-8	Cellulase	Yes
9004-34-6	Cellulose	Yes
9004-32-4	Cellulose, carboxymethyl ether, sodium salt	Yes
16887-00-6	Chloride	Yes
7782-50-5	Chlorine	Yes
10049-04-4	Chlorine dioxide	Yes
124-48-1	Chlorodibromomethane	Yes
67-66-3	Chloroform	Yes
74-87-3	Chloromethane	Yes
78-73-9	Choline bicarbonate	Yes
67-48-1	Choline chloride	Yes
7440-47-3	Chromium	Yes
16065-83-1	Chromium (III), insoluble salts	Yes
18540-29-9	Chromium (VI)	Yes
39430-51-8	Chromium acetate, basic	Yes
1066-30-4	Chromium(III) acetate	Yes
77-92-9	Citric acid	Yes
8000-29-1	Citronella oil	Yes
94266-47-4	Citrus extract	Yes
50815-10-6	Coal, granular	Yes
7440-48-4	Cobalt	Yes
71-48-7	Cobalt(II) acetate	Yes
68424-94-2	Coco-betaine	Yes
68603-42-9	Coconut oil acid/Diethanolamine condensate (2:1)	Yes
61789-18-2	Coconut trimethylammonium chloride	Yes
7440-50-8	Copper	Yes
7440-50-8	Copper	Yes
7758-98-7	Copper sulfate	Yes
7758-89-6	Copper(I) chloride	Yes
7681-65-4	Copper(I) iodide	Yes
7447-39-4	Copper(II) chloride	Yes
68525-86-0	Corn flour	Yes
11138-66-2	Corn sugar gum	Yes
1302-74-5	Corundum (Aluminum oxide)	Yes
68308-87-2	Cottonseed, flour	Yes
91-64-5	Coumarin	Yes

14464-46-1	Cristobalite	Yes
15468-32-3	Crystalline silica, tridymite	Yes
98-82-8	Cumene	Yes
10125-13-0	Cupric chloride dihydrate	Yes
57-12-5	Cyanide, free	Yes
110-82-7	Cyclohexane	Yes
108-94-1	Cyclohexanone	Yes
50-70-4	D-Glucitol	Yes
526-95-4	D-Gluconic acid	Yes
3149-68-6	D-Glucopyranoside, methyl	Yes
50-99-7	D-Glucose	Yes
10326-41-7	D-Lactic acid	Yes
5989-27-5	D-Limonene	Yes
18472-87-2	D&C Red 28	Yes
533-74-4	Dazomet	Yes
1120-24-7	Decyldimethylamine	Yes
319-86-8	delta-Hexachlorocyclohexane	Yes
7789-20-0	Deuterium oxide	Yes
31291-60-8	Di-sec-butylphenol	Yes
117-81-7	Di(2-ethylhexyl) phthalate	Yes
117-81-7	Di(2-ethylhexyl) phthalate	Yes
7727-54-0	Diammonium peroxydisulfate	Yes
68855-54-9	Diatomaceous earth	Yes
91053-39-3	Diatomaceous earth, calcined	Yes
53-70-3	Dibenz(a,h)anthracene	Yes
64-02-8	Ethylenediaminetetraacetic acid tetrasodium salt	Yes
67989-88-2	Ethylenediaminetetraacetic acid, diammonium copper salt	Yes
139-33-3	Ethylenediaminetetraacetic acid, disodium salt	Yes
74-86-2	Ethyne	Yes
68604-35-3	Fatty acids, C 8-18 and C18-unsaturated compounds with diethanolamine	Yes
70321-73-2	Fatty acids, C14-18 and C16-18-unsatd., distn. residues	Yes
61788-89-4	Fatty acids, C18-unsatd., dimers	Yes
61791-29-5	Fatty acids, coco, ethoxylated	Yes
61791-08-0	Fatty acids, coco, reaction products with ethanolamine, ethoxylated	Yes

61790-90-7	Fatty acids, tall oil, hexa esters with sorbitol, ethoxylated	Yes
68188-40-9	Fatty acids, tall oil, reaction products with acetophenone, formaldehyde and thiourea	No
61790-12-3	Fatty acids, tall-oil	Yes
61790-69-0	Fatty acids, tall-oil, reaction products with diethylenetriamine	Yes
8052-48-0	Fatty acids, tallow, sodium salts	Yes
68153-72-0	Fatty acids, vegetable-oil, reaction products with diethylenetriamine	Yes
3844-45-9	FD&C Blue no. 1	Yes
7705-08-0	Ferric chloride	Yes
10028-22-5	Ferric sulfate	Yes
17375-41-6	Ferrous sulfate monohydrate	Yes
65997-17-3	Fiberglass	Yes
206-44-0	Fluoranthene	Yes
86-73-7	Fluorene	Yes
16984-48-8	Fluoride	Yes
50-00-0	Formaldehyde	Yes
29316-47-0	Formaldehyde polymer with 4,1,1-(dimethylethyl)phenol and methyloxirane	No
63428-92-2	Formaldehyde polymer with methyl oxirane, 4-nonylphenol and oxirane	Yes
28906-96-9	Formaldehyde, polymer with 2-(chloromethyl)oxirane and 4,4'-(1-methylethylidene)bis[phenol]	Yes
30704-64-4	Formaldehyde, polymer with 4-(1,1-dimethylethyl)phenol, 2-methyloxirane and oxirane	No
30846-35-6	Formaldehyde, polymer with 4-nonylphenol and oxirane	Yes
35297-54-2	Formaldehyde, polymer with ammonia and phenol	Yes
25085-75-0	Formaldehyde, polymer with bisphenol A	Yes
70750-07-1	Formaldehyde, polymer with N1-(2-aminoethyl)-1,2-ethanediamine, benzylated	Yes
55845-06-2	Formaldehyde, polymer with nonylphenol and oxirane	Yes

153795-76-7	Formaldehyde, polymers with branched 4-nonylphenol, ethylene oxide and propylene oxide	Yes
75-12-7	Formamide	Yes
64-18-6	Formic acid	Yes
590-29-4	Formic acid, potassium salt	Yes
68476-30-2	Fuel oil, no. 2	Yes
68334-30-5	Fuels, diesel	Yes
68476-34-6	Fuels, diesel, no. 2	Yes
8031-18-3	Fuller's earth	Yes
110-17-8	Fumaric acid	Yes
98-01-1	Furfural	Yes
98-00-0	Furfuryl alcohol	Yes
64741-43-1	Gas oils, petroleum, straight-run	Yes
9000-70-8	Gelatin	Yes
12002-43-6	Gilsonite	Yes
133-42-6	Gluconic acid	Yes
111-30-8	Glutaraldehyde	Yes
56-81-5	Glycerin, natural	Yes
135-37-5	Glycine, N-(carboxymethyl)-N-(2-hydroxyethyl)-, disodium salt	Yes
139-89-9	Glycine, N-[2-[bis(carboxymethyl)amino]ethyl]-N-(2-hydroxyethyl)-, trisodium salt	Yes
150-25-4	Glycine, N,N-bis(2-hydroxyethyl)-	Yes
5064-31-3	Glycine, N,N-bis(carboxymethyl)-, trisodium salt	Yes
79-14-1	Glycolic acid	Yes
2836-32-0	Glycolic acid sodium salt	Yes
107-22-2	Glyoxal	Yes
298-12-4	Glyoxylic acid	Yes
9000-30-0	Guar gum	Yes
68130-15-4	Guar gum, carboxymethyl 2-hydroxypropyl ether, sodium salt	Yes
13397-24-5	Gypsum	Yes
67891-79-6	Heavy aromatic distillate	Yes
1317-60-8	Hematite	Yes
9025-56-3	Hemicellulase enzyme concentrate	Yes
76-44-8	Heptachlor	Yes
1024-57-3	Heptachlor epoxide	Yes

142-82-5	Heptane	Yes
111-14-8	Heptanoic acid	Yes
68526-88-5	Heptene, hydroformylation products, high-boiling	Yes
57-09-0	Hexadecyltrimethylammonium bromide	Yes
110-54-3	Hexane	Yes
124-04-9	Hexanedioic acid	Yes
142-62-1	Hexanoic acid	Yes
1415-93-6	Humic acids, commercial grade	Yes
68956-56-9	Hydrocarbons, terpene processing by-products	Yes
7647-01-0	Hydrochloric acid	Yes
7664-39-3	Hydrogen fluoride	Yes
7722-84-1	Hydrogen peroxide	Yes
7783-06-4	Hydrogen sulfide	Yes
9004-62-0	Hydroxyethylcellulose	Yes
5470-11-1	Hydroxylamine hydrochloride	Yes
10039-54-0	Hydroxylamine sulfate (2:1)	Yes
9004-64-2	Hydroxypropyl cellulose	Yes
39421-75-5	Hydroxypropyl guar gum	Yes
193-39-5	Indeno(1,2,3-cd)pyrene	Yes
120-72-9	Indole	Yes
430439-54-6	Inulin, carboxymethyl ether, sodium salt	No
12030-49-8	Iridium oxide	Yes
7439-89-6	Iron	Yes
7439-89-6	Iron	Yes
1317-61-9	Iron oxide (Fe3O4)	Yes
1332-37-2	Iron(II) oxide	Yes
7720-78-7	Iron(II) sulfate	Yes
7782-63-0	Iron(II) sulfate heptahydrate	Yes
1309-37-1	Iron(III) oxide	Yes
89-65-6	Isoascorbic acid	Yes
75-28-5	Isobutane	Yes
26952-21-6	Isooctanol	Yes
123-51-3	Isopentyl alcohol	Yes
67-63-0	Isopropanol	Yes
67-63-0	Isopropanol	Yes
42504-46-1	Isopropanolamine dodecylbenzenesulfonate	Yes
75-31-0	Isopropylamine	Yes

68909-80-8	Isoquinoline, reaction products with benzyl chloride and quinoline	No
35674-56-7	Isoquinolinium, 2-(phenylmethyl)-, chloride	No
9043-30-5	Isotridecanol, ethoxylated	Yes
1332-58-7	Kaolin	Yes
8008-20-6	Kerosine (petroleum)	Yes
64742-81-0	Kerosine, petroleum, hydrodesulfurized	Yes
61790-53-2	Kieselguhr	Yes
1302-76-7	Kyanite	Yes
4511-42-6	L-Dilactide	Yes
79-33-4	L-Lactic acid	Yes
50-21-5	Lactic acid	Yes
63-42-3	Lactose	Yes
13197-76-7	Lauryl hydroxysultaine	Yes
8022-15-9	Lavandula hybrida abrial herb oil	Yes
7439-92-1	Lead	Yes
7439-92-1	Lead	Yes
8002-43-5	Lecithin	Yes
129521-66-0	Lignite	Yes
8062-15-5	Lignosulfuric acid	Yes
1317-65-3	Limestone	Yes
58-89-9	Lindane	Yes
8001-26-1	Linseed oil	Yes
7439-93-2	Lithium	Yes
7439-95-4	Magnesium	Yes
546-93-0	Magnesium carbonate (1:1)	Yes
7786-30-3	Magnesium chloride	Yes
7791-18-6	Magnesium chloride hexahydrate	Yes
1309-42-8	Magnesium hydroxide	Yes
19086-72-7	Magnesium iron silicate	No
10377-60-3	Magnesium nitrate	Yes
1309-48-4	Magnesium oxide	Yes
14452-57-4	Magnesium peroxide	Yes
12057-74-8	Magnesium phosphide	Yes
1343-88-0	Magnesium silicate	Yes
26099-09-2	Maleic acid homopolymer	Yes
7439-96-5	Manganese	Yes
7439-97-6	Mercury	Yes
25988-97-0	Methanamine-N-methyl polymer with chloromethyl oxirane	Yes

74-82-8	Methane	Yes
67-56-1	Methanol	Yes
67-56-1	Methanol	Yes
100-97-0	Methenamine	Yes
625-45-6	Methoxyacetic acid	Yes
74-83-9	Methyl bromide	Yes
9004-67-5	Methyl cellulose	Yes
78-93-3	Methyl ethyl ketone	Yes
119-36-8	Methyl salicylate	Yes
78-94-4	Methyl vinyl ketone	Yes
108-87-2	Methylcyclohexane	Yes
6317-18-6	Methylene bis(thiocyanate)	Yes
66204-44-2	Methylenebis(5-methyloxazolidine)	Yes
68891-11-2	Methyloxirane polymer with oxirane, mono (nonylphenol) ether, branched	Yes
12001-26-2	Mica	Yes
8012-95-1	Mineral oil - includes paraffin oil	Yes
64475-85-0	Mineral spirits	Yes
7439-98-7	Molybdenum	Yes
26038-87-9	Monoethanolamine borate (1:x)	Yes
1318-93-0	Montmorillonite	Yes
110-91-8	Morpholine	Yes
78-21-7	Morpholinium, 4-ethyl-4-hexadecyl-, ethyl sulfate	Yes
1302-93-8	Mullite	Yes
46830-22-2	N-(2-Acryloyloxyethyl)-N-benzyl-N,N-dimethylammonium chloride	Yes
872-50-4	N-Methyl-2-pyrrolidone	Yes
68213-98-9	N-Methyl-N-hydroxyethyl-N-hydroxyethoxyethylamine	No
105-59-9	N-Methyldiethanolamine	Yes
109-83-1	N-Methylethanolamine	Yes
86-30-6	N-Nitrosodiphenylamine	Yes
13127-82-7	N-Oleyl diethanolamide	Yes
1184-78-7	N,N-Dimethyl-methanamine-N-oxide	Yes
2605-79-0	N,N-Dimethyldecylamine oxide	Yes
68-12-2	N,N-Dimethylformamide	Yes
593-81-7	N,N-Dimethylmethanamine hydrochloride	Yes
1613-17-8	N,N-Dimethyloctadecylamine hydrochloride	No

54076-97-0	N,N,N-Trimethyl-2[1-oxo-2-propenyl]oxy ethanaminimum chloride, homopolymer	Yes
19277-88-4	N,N,N-Trimethyl-3-((1-oxooctadecyl)amino)-1-propanaminium methyl sulfate	No
112-03-8	N,N,N-Trimethyloctadecan-1-aminium chloride	Yes
109-46-6	N,N'-Dibutylthiourea	Yes
110-26-9	N,N'-Methylenebisacrylamide	Yes
64741-68-0	Naphtha, petroleum, heavy catalytic reformed	Yes
64742-48-9	Naphtha, petroleum, hydrotreated heavy	Yes
91-20-3	Naphthalene	Yes
91-20-3	Naphthalene	Yes
93-18-5	Naphthalene, 2-ethoxy-	Yes
28757-00-8	Naphthalenesulfonic acid, bis(1-methylethyl)-	Yes
99811-86-6	Naphthalenesulphonic acid, bis (1-methylethyl)-methyl derivatives	No
68410-62-8	Naphthenic acid ethoxylate	Yes
7440-02-0	Nickel	Yes
7786-81-4	Nickel sulfate	Yes
10101-97-0	Nickel(II) sulfate hexahydrate	Yes
61790-29-2	Nitriles, tallow, hydrogenated	Yes
4862-18-4	Nitrilotriacetamide	No
139-13-9	Nitrilotriacetic acid	Yes
18662-53-8	Nitrilotriacetic acid trisodium monohydrate	Yes
7727-37-9	Nitrogen	Yes
25154-52-3	Nonylphenol (mixed)	Yes
8000-48-4	Oil of eucalyptus	Yes
8007-02-1	Oil of lemongrass	Yes
8000-25-7	Oil of rosemary	Yes
112-80-1	Oleic acid	Yes
1317-71-1	Olivine	Yes
8028-48-6	Orange terpenes	Yes
68649-29-6	Oxirane, methyl-, polymer with oxirane, mono-C10-16-alkyl ethers, phosphates	Yes

51838-31-4	Oxiranemethanaminium, N,N,N-trimethyl-, chloride, homopolymer	Yes
7782-44-7	Oxygen	Yes
10028-15-6	Ozone	Yes
99-87-6	p-Cymene	Yes
106-42-3	p-Xylene	Yes
72-55-9	p,p'-DDE	Yes
8002-74-2	Paraffin waxes and Hydrocarbon waxes	Yes
30525-89-4	Paraformaldehyde	Yes
4067-16-7	Pentaethylenehexamine	Yes
109-66-0	Pentane	Yes
109-52-4	Pentanoic acid	Yes
628-63-7	Pentyl acetate	Yes
540-18-1	Pentyl butyrate	Yes
79-21-0	Peracetic acid	Yes
93763-70-3	Perlite	Yes
64743-01-7	Petrolatum, petroleum, oxidized	Yes
8002-05-9	Petroleum	Yes
6742-47-8	Petroleum distillate hydrotreated light	No
85-01-8	Phenanthrene	Yes
85-01-8	Phenanthrene	Yes
108-95-2	Phenol	Yes
108-95-2	Phenol	Yes
25068-38-6	Phenol, 4,4'-(1-methylethylidene)bis-, polymer with 2-(chloromethyl)oxirane	Yes
9003-35-4	Phenol, polymer with formaldehyde	Yes
298-02-2	Phorate	Yes
7803-51-2	Phosphine	Yes
13598-36-2	Phosphonic acid	Yes
29712-30-9	Phosphonic acid (dimethylamino(methylene))	No
129828-36-0	Phosphonic acid, (((2-[(2-hydroxyethyl)(phosphonomethyl)amino)ethyl)imino]bis(methylene))bis-, compd. with 2-aminoethanol	No
67953-76-8	Phosphonic acid, (1-hydroxyethylidene)bis-, potassium salt	Yes
3794-83-0	Phosphonic acid, (1-hydroxyethylidene)bis-, tetrasodium salt	Yes

15827-60-8	Phosphonic acid, [[(phosphonomethyl)imino]bis[2,1-ethanediylnitrilobis(methylene)]]tetrakis-	Yes
70714-66-8	Phosphonic acid, [[(phosphonomethyl)imino]bis[2,1-ethanediylnitrilobis(methylene)]]tetrakis-, ammonium salt (1:x)	No
22042-96-2	Phosphonic acid, [[(phosphonomethyl)imino]bis[2,1-ethanediylnitrilobis(methylene)]]tetrakis-, sodium salt	Yes
34690-00-1	Phosphonic acid, [[(phosphonomethyl)imino]bis[6,1-hexanediylnitrilobis(methylene)]]tetrakis-	Yes
7664-38-2	Phosphoric acid	Yes
7785-88-8	Phosphoric acid, aluminium sodium salt	Yes
7783-28-0	Phosphoric acid, diammonium salt	Yes
68412-60-2	Phosphoric acid, mixed decyl and Et and octyl esters	Yes
10294-56-1	Phosphorous acid	Yes
7723-14-0	Phosphorus	Yes
85-44-9	Phthalic anhydride	Yes
8002-09-3	Pine oils	Yes
25038-54-4	Policapram (Nylon 6)	Yes
62649-23-4	Poly (acrylamide-co-acrylic acid), partial sodium salt	Yes
34398-01-1	Poly-(oxy-1,2-ethanediyl)-alpha-undecyl-omega-hydroxy	Yes
26680-10-4	Poly(lactide)	Yes
127087-87-0	Poly(oxy-1,2-ethanediyl)-nonylphenyl-hydroxy branched	Yes
9014-93-1	Poly(oxy-1,2-ethanediyl), .alpha.-(dinonylphenyl)-.omega.-hydroxy-	Yes
9016-45-9	Poly(oxy-1,2-ethanediyl), .alpha.-(nonylphenyl)-.omega.-hydroxy-	Yes
51811-79-1	Poly(oxy-1,2-ethanediyl), .alpha.-(nonylphenyl)-.omega.-hydroxy-, phosphate	Yes
68987-90-6	Poly(oxy-1,2-ethanediyl), .alpha.-(octylphenyl)-.omega.-hydroxy-, branched	Yes
9004-96-0	Poly(oxy-1,2-ethanediyl), .alpha.-[(9Z)-1-oxo-9-octadecenyl]-.omega.-hydroxy-	Yes
68891-38-3	Poly(oxy-1,2-ethanediyl), .alpha.-sulfo-.omega.-hydroxy-, C12-14-alkyl ethers, sodium salts	Yes

26635-93-8	Poly(oxy-1,2-ethanediyl), .alpha.,.alpha.'-[[(9Z)-9-octadecenylimino]di-2,1-ethanediyl]bis[.omega.-hydroxy-	Yes
61723-83-9	Poly(oxy-1,2-ethanediyl), a-hydro-w-hydroxy-, ether with D-glucitol (2:1), tetra-(9Z)-9-octadecenoate	Yes
68015-67-8	Poly(oxy-1,2-ethanediyl), alpha-(2,3,4,5-tetramethylnonyl)-omega-hydroxy	Yes
68412-53-3	Poly(oxy-1,2-ethanediyl), alpha-(nonylphenyl)-omega-hydroxy-,branched, phosphates	Yes
31726-34-8	Poly(oxy-1,2-ethanediyl), alpha-hexyl-omega-hydroxy	Yes
56449-46-8	Poly(oxy-1,2-ethanediyl), alpha-hydro-omega-hydroxy-, (9Z)-9-octadecenoate	Yes
65545-80-4	Poly(oxy-1,2-ethanediyl), alpha-hydro-omega-hydroxy-, ether with alpha-fluoro-omega-(2-hydroxyethyl)poly(difluoromethylene) (1:1)	Yes
27306-78-1	Poly(oxy-1,2-ethanediyl), alpha-methyl-omega-(3-(1,3,3,3-tetramethyl-1-((trimethylsilyl)oxy)-1-disiloxanyl)propoxy)	Yes
9081-17-8	Poly(oxy-1,2-ethanediyl), alpha-sulfo-omega–(nonylphenoxy)-	No
52286-19-8	Poly(oxy-1,2-ethanediyl), alpha-sulfo-omega-(decyloxy)-, ammonium salt (1:1)	Yes
63428-86-4	Poly(oxy-1,2-ethanediyl), alpha-sulfo-omega-(hexyloxy)-, ammonium salt (1:1)	No
68037-05-8	Poly(oxy-1,2-ethanediyl), alpha-sulfo-omega-(hexyloxy)-, C6-10-alkyl ethers, ammonium salts	Yes
52286-18-7	Poly(oxy-1,2-ethanediyl), alpha-sulfo-omega-(octyloxy)-, ammonium salt (1:1)	Yes
68890-88-0	Poly(oxy-1,2-ethanediyl), alpha-sulfo-omega-hydroxy-, C10-12-alkyl ethers, ammonium salts	Yes
24938-91-8	Poly(oxy-1,2-ethanediyl), alpha-tridecyl-omega-hydroxy-	Yes

127036-24-2	Poly(oxy-1,2-ethanediyl), alpha-undecyl-omega-hydroxy-, branched and linear	Yes
68412-54-4	Poly(oxy-1,2-ethanediyl),alpha-(4-nonylphenyl)-omega-hydroxy-,branched	Yes
25704-18-1	Poly(sodium-p-styrenesulfonate)	Yes
32131-17-2	Poly[imino(1,6-dioxo-1,6-hexanediyl)imino-1,6-hexanediyl]	Yes
9003-05-8	Polyacrylamide	Yes
66019-18-9	Polyacrylic acid, sodium bisulfite terminated	Yes
25322-68-3	Polyethylene glycol	Yes
9004-98-2	Polyethylene glycol (9Z)-9-octadecenyl ether	Yes
68187-85-9	Polyethylene glycol ester with tall oil fatty acid	No
68891-29-2	Polyethylene glycol mono-C8-10-alkyl ether sulfate ammonium	Yes
9036-19-5	Polyethylene glycol mono(octylphenyl) ether	Yes
9004-77-7	Polyethylene glycol monobutyl ether	Yes
9046-01-9	Polyethylene glycol tridecyl ether phosphate	Yes
9002-98-6	Polyethyleneimine	Yes
25618-55-7	Polyglycerol	Yes
9005-70-3	Polyoxyethylene sorbitan trioleate	Yes
26027-38-3	Polyoxyethylene(10)nonylphenyl ether	Yes
9046-10-0	Polyoxypropylenediamine	Yes
68131-72-6	Polyphosphoric acids, esters with triethanolamine, sodium salts	Yes
68915-31-1	Polyphosphoric acids, sodium salts	Yes
25322-69-4	Polypropylene glycol	Yes
68683-13-6	Polypropylene glycol glycerol triether, epichlorohydrin, bisphenol A polymer	No
9011-19-2	Polysiloxane	Yes
9005-64-5	Polysorbate 20	Yes
9003-20-7	Polyvinyl acetate copolymer	Yes
9002-89-5	Polyvinyl alcohol	Yes
9002-85-1	Polyvinylidene chloride	Yes
65997-15-1	Portland cement	Yes
7440-09-7	Potassium	Yes
127-08-2	Potassium acetate	Yes
1327-44-2	Potassium aluminum silicate	Yes

29638-69-5	Potassium antimonate	Yes
12712-38-8	Potassium borate	Yes
20786-60-1	Potassium borate (1:x)	Yes
6381-79-9	Potassium carbonate sesquihydrate	Yes
7447-40-7	Potassium chloride	Yes
7778-50-9	Potassium dichromate	Yes
1310-58-3	Potassium hydroxide	Yes
7681-11-0	Potassium iodide	Yes
13709-94-9	Potassium metaborate	Yes
143-18-0	Potassium oleate	Yes
12136-45-7	Potassium oxide	Yes
7727-21-1	Potassium persulfate	Yes
7778-80-5	Potassium sulfate	Yes
74-98-6	Propane	Yes
2997-92-4	Propanimidamide,2,2”-aAzobis[(2-methyl-,amidinopropane) dihydrochloride	Yes
34590-94-8	Propanol, 1(or 2)-(2-methoxymethylethoxy)-	Yes
107-19-7	Propargyl alcohol	Yes
79-09-4	Propionic acid	Yes
103-65-1	Propylbenzene	Yes
108-32-7	Propylene carbonate	Yes
15220-87-8	Propylene pentamer	Yes
129-00-0	Pyrene	Yes
110-86-1	Pyridine	Yes
68391-11-7	Pyridine, alkyl derivs.	Yes
100765-57-9	Pyridinium, 1-(phenylmethyl)-, alkyl derivs., chlorides	Yes
70914-44-2	Pyridinium, 1-(phenylmethyl)-, C7-8-alkyl derivs., chlorides	Yes
289-95-2	Pyrimidine	Yes
109-97-7	Pyrrole	Yes
14808-60-7	Quartz	Yes
308074-31-9	Quaternary ammonium compounds (2-ethylhexyl) hydrogenated tallow alkyl)dimethyl, methyl sulfates	Yes
68607-28-3	Quaternary ammonium compounds, (oxydi-2,1-ethanediyl)bis[coco alkyldimethyl, dichlorides	Yes
68989-00-4	Quaternary ammonium compounds, benzyl-C10-16-alkyldimethyl, chlorides	Yes

68424-85-1	Quaternary ammonium compounds, benzyl-C12-16-alkyldimethyl, chlorides	Yes
68391-01-5	Quaternary ammonium compounds, benzyl-C12-18-alkyldimethyl, chlorides	Yes
68153-30-0	Quaternary ammonium compounds, benzylbis(hydrogenated tallow alkyl)methyl, salts with bentonite	Yes
61789-68-2	Quaternary ammonium compounds, benzylcoco alkylbis(hydroxyethyl), chlorides	No
68953-58-2	Quaternary ammonium compounds, bis(hydrogenated tallow alkyl)dimethyl, salts with bentonite	Yes
71011-27-3	Quaternary ammonium compounds, bis(hydrogenated tallow alkyl)dimethyl, salts with hectorite	Yes
68424-95-3	Quaternary ammonium compounds, di-C8-10-alkyldimethyl, chlorides	Yes
61789-77-3	Quaternary ammonium compounds, dicoco alkyldimethyl, chlorides	Yes
68607-29-4	Quaternary ammonium compounds, pentamethyltallow alkyltrimethylenedi-, dichlorides	Yes
8030-78-2	Quaternary ammonium compounds, trimethyltallow alkyl, chlorides	Yes
91-22-5	Quinoline	Yes
13982-63-3	Radium 226	Yes
7440-14-4	Radium 226,228	No
15262-20-1	Radium 228	No
68514-29-4	Raffinates (petroleum)	Yes
64741-85-1	Raffinates, petroleum, sorption process	Yes
64742-01-4	Residual oils, petroleum, solvent-refined	Yes
64741-67-9	Residues, petroleum, catalytic reformer fractionator	Yes
81-88-9	Rhodamine B	Yes
8050-09-7	Rosin	Yes
94-59-7	Safrole	Yes
12060-08-1	Scandium oxide	Yes
135-98-8	sec-Butylbenzene	Yes
7782-49-2	Selenium	Yes
63800-37-3	Sepiolite	Yes

68611-44-9	Silane, dichlorodimethyl-, reaction products with silica	Yes
7631-86-9	Silica	Yes
112926-00-8	Silica gel, cryst. -free	Yes
112945-52-5	Silica, amorphous, fumed, cryst.-free	Yes
60676-86-0	Silica, vitreous	Yes
55465-40-2	Silicic acid, aluminum potassium sodium salt	No
7440-21-3	Silicon (elemental)	Yes
68037-74-1	Siloxanes and silicones, di-Me, polymers with Me silsesquioxanes	Yes
67762-90-7	Siloxanes and Silicones, di-Me, reaction products with silica	Yes
63148-52-7	Siloxanes and silicones, dimethyl,	Yes
7440-22-4	Silver	Yes
7440-23-5	Sodium	Yes
5324-84-5	Sodium 1-octanesulfonate	Yes
2492-26-4	Sodium 2-mercaptobenzothiolate	Yes
127-09-3	Sodium acetate	Yes
532-32-1	Sodium benzoate	Yes
144-55-8	Sodium bicarbonate	Yes
7631-90-5	Sodium bisulfite	Yes
1333-73-9	Sodium borate	Yes
7789-38-0	Sodium bromate	Yes
7647-15-6	Sodium bromide	Yes
1004542-84-0	Sodium bromosulfamate	No
68610-44-6	Sodium caprylamphopropionate	Yes
497-19-8	Sodium carbonate	Yes
7775-09-9	Sodium chlorate	Yes
7647-14-5	Sodium chloride	Yes
7758-19-2	Sodium chlorite	Yes
3926-62-3	Sodium chloroacetate	Yes
68608-68-4	Sodium cocaminopropionate	Yes
527-07-1	Sodium D-gluconate	Yes
142-87-0	Sodium decyl sulfate	Yes
126-96-5	Sodium diacetate	Yes
2893-78-9	Sodium dichloroisocyanurate	Yes
151-21-3	Sodium dodecyl sulfate	Yes
6381-77-7	Sodium erythorbate (1:1)	Yes
126-92-1	Sodium ethasulfate	Yes
141-53-7	Sodium formate	Yes

7681-38-1	Sodium hydrogen sulfate	Yes
1310-73-2	Sodium hydroxide	Yes
7681-52-9	Sodium hypochlorite	Yes
7681-82-5	Sodium iodide	Yes
8061-51-6	Sodium ligninsulfonate	Yes
18016-19-8	Sodium maleate (1:x)	Yes
7681-57-4	Sodium metabisulfite	Yes
7775-19-1	Sodium metaborate	Yes
16800-11-6	Sodium metaborate dihydrate	No
10555-76-7	Sodium metaborate tetrahydrate	Yes
6834-92-0	Sodium metasilicate	Yes
137-20-2	Sodium N-methyl-N-oleoyltaurate	Yes
7631-99-4	Sodium nitrate	Yes
7632-00-0	Sodium nitrite	Yes
142-31-4	Sodium octyl sulfate	Yes
1313-59-3	Sodium oxide	Yes
11138-47-9	Sodium perborate	Yes
10486-00-7	Sodium perborate tetrahydrate	Yes
7632-04-4	Sodium peroxoborate	Yes
7775-27-1	Sodium persulfate	Yes
7632-05-5	Sodium phosphate	Yes
9084-06-4	Sodium polynaphthalenesulfonate	Yes
7758-16-9	Sodium pyrophosphate	Yes
54-21-7	Sodium salicylate	Yes
533-96-0	Sodium sesquicarbonate	Yes
1344-09-8	Sodium silicate	Yes
9063-38-1	Sodium starch glycolate	Yes
7757-82-6	Sodium sulfate	Yes
7757-83-7	Sodium sulfite	Yes
540-72-7	Sodium thiocyanate	Yes
7772-98-7	Sodium thiosulfate	Yes
10102-17-7	Sodium thiosulfate, pentahydrate	Yes
650-51-1	Sodium trichloroacetate	Yes
1300-72-7	Sodium xylenesulfonate	Yes
10377-98-7	Sodium zirconium lactate	No
64742-88-7	Solvent naphtha (petroleum), medium aliph.	Yes
64742-96-7	Solvent naphtha, petroleum, heavy aliph.	Yes
64742-94-5	Solvent naphtha, petroleum, heavy arom.	Yes

64742-95-6	Solvent naphtha, petroleum, light arom.	Yes
8007-43-0	Sorbitan, (9Z)-9-octadecenoate (2:3)	Yes
1338-43-8	Sorbitan, mono-(9Z)-9-octadecenoate	Yes
9005-65-6	Sorbitan, mono-(9Z)-9-octadecenoate, poly(oxy-1,2-ethanediyl) derivis.	Yes
9005-67-8	Sorbitan, monooctadecenoate, poly(oxy-1,2-ethanediyl) derivis.	Yes
26266-58-0	Sorbitan, tri-(9Z)-9-octadecenoate	Yes
10025-69-1	Stannous chloride dihydrate	Yes
9005-25-8	Starch	Yes
68131-87-3	Steam cracked distillate, cyclodiene dimer, dicyclopentadiene polymer	Yes
8052-41-3	Stoddard solvent	Yes
7440-24-6	Strontium	Yes
10476-85-4	Strontium chloride	Yes
100-42-5	Styrene	Yes
57-50-1	Sucrose	Yes
5329-14-6	Sulfamic acid	Yes
14808-79-8	Sulfate	No
14808-79-8	Sulfate	Yes
14265-45-3	Sulfite	Yes
68201-64-9	Sulfomethylated quebracho	No
68608-21-9	Sulfonic acids, C10-16-alkane, sodium salts	Yes
68439-57-6	Sulfonic acids, C14-16-alkane hydroxy and C14-16-alkene, sodium salts	Yes
61789-85-3	Sulfonic acids, petroleum	Yes
68608-26-4	Sulfonic acids, petroleum, sodium salts	Yes
7446-09-5	Sulfur dioxide	Yes
7664-93-9	Sulfuric acid	Yes
68955-19-1	Sulfuric acid, mono-C12-18-alkyl esters, sodium salts	Yes
68187-17-7	Sulfuric acid, mono-C6-10-alkyl esters, ammonium salts	Yes
14807-96-6	Talc	Yes
8002-26-4	Tall oil	Yes
61791-36-4	Tall oil imidazoline	No
68092-28-4	Tall oil, compound with diethanolamine	Yes
65071-95-6	Tall oil, ethoxylated	Yes
8016-81-7	Tall-oil pitch	Yes
61790-60-1	Tallow alkyl amines acetate	Yes

72480-70-7	Tar bases, quinoline derivatives, benzyl chloride-quaternized	No
68647-72-3	Terpenes and Terpenoids, sweet orange-oil	Yes
8000-41-7	Terpineol	Yes
75-91-2	tert-Butyl hydroperoxide	Yes
614-45-9	tert-Butyl perbenzoate	Yes
12068-35-8	Tetra-calcium-alumino-ferrite	Yes
127-18-4	Tetrachloroethylene	Yes
629-59-4	Tetradecane	Yes
139-08-2	Tetradecyldimethylbenzylammonium chloride	Yes
112-60-7	Tetraethylene glycol	Yes
112-57-2	Tetraethylenepentamine	Yes
55566-30-8	Tetrakis(hydroxymethyl)phosphonium sulfate	Yes
681-84-5	Tetramethyl orthosilicate	Yes
75-57-0	Tetramethylammonium chloride	Yes
7440-28-0	Thallium and Compounds	Yes
1762-95-4	Thiocyanic acid, ammonium salt	Yes
68-11-1	Thioglycolic acid	Yes
62-56-6	Thiourea	Yes
68527-49-1	Thiourea, polymer with formaldehyde and 1-phenylethanone	No
68917-35-1	Thuja plicata donn ex. D. don leaf oil	No
7440-31-5	Tin	Yes
7772-99-8	Tin(II) chloride	Yes
7440-32-6	Titanium	Yes
13463-67-7	Titanium dioxide	Yes
74665-17-1	Titanium, iso-Pr alc. triethanolamine complexes	Yes
36673-16-2	Titanium(4+) 2-[bis(2-hydroxyethyl)amino]ethanolate propan-2-olate (1:2:2)	No
108-88-3	Toluene	Yes
108-88-3	Toluene	Yes
126-73-8	Tributyl phosphate	Yes
81741-28-8	Tributyltetradecylphosphonium chloride	Yes
7758-87-4	Tricalcium phosphate	Yes
12168-85-3	Tricalcium silicate	Yes

87-90-1	Trichloroisocyanuric acid	Yes
629-50-5	Tridecane	Yes
102-71-6	Triethanolamine	Yes
68299-02-5	Triethanolamine hydroxyacetate	No
68131-71-5	Triethanolamine polyphosphate ester	No
77-93-0	Triethyl citrate	Yes
78-40-0	Triethyl phosphate	Yes
112-27-6	Triethylene glycol	Yes
112-24-3	Triethylenetetramine	Yes
122-20-3	Triisopropanolamine	Yes
14002-32-5	Trimethanolamine	No
121-43-7	Trimethyl borate	Yes
25551-13-7	Trimethylbenzene	Yes
7758-29-4	Triphosphoric acid, pentasodium salt	Yes
1317-95-9	Tripoli	Yes
6100-05-6	Tripotassium citrate monohydrate	Yes
25498-49-1	Tripropylene glycol monomethyl ether	Yes
68-04-2	Trisodium citrate	Yes
6132-04-3	Trisodium citrate dihydrate	Yes
150-38-9	Trisodium ethylenediaminetetraacetate	Yes
19019-43-3	Trisodium ethylenediaminetriacetate	Yes
7601-54-9	Trisodium phosphate	Yes
10101-89-0	Trisodium phosphate dodecahydrate	Yes
77-86-1	Tromethamine	Yes
73049-73-7	Tryptone	Yes
1319-33-1	Ulexite	Yes
1120-21-4	Undecane	Yes
57-13-6	Urea	Yes
7440-62-2	Vanadium	Yes
1318-00-9	Vermiculite	Yes
24937-78-8	Vinyl acetate ethylene copolymer	Yes
25038-72-6	Vinylidene chloride/methylacrylate copolymer	Yes
7732-18-5	Water	Yes
8042-47-5	White mineral oil, petroleum	Yes
1330-20-7	Xylenes	Yes
8013-01-2	Yeast extract	Yes
7440-66-6	Zinc	Yes
7440-66-6	Zinc	Yes
3486-35-9	Zinc carbonate	Yes
7646-85-7	Zinc chloride	Yes

1314-13-2	Zinc oxide	Yes
7440-67-7	Zirconium	Yes
13746-89-9	Zirconium nitrate	Yes
62010-10-0	Zirconium oxide sulfate	No
7699-43-6	Zirconium oxychloride	Yes
197980-53-3	Zirconium, 1,1'-((2-((2-hydroxyethyl)(2-hydroxypropyl)amino)ethyl)imino)bis(2-propanol) complexes	No
68909-34-2	Zirconium, acetate lactate oxo ammonium complexes	No
174206-15-6	Zirconium, chloro hydroxy lactate oxo sodium complexes	No
113184-20-6	Zirconium, hydroxylactate sodium complexes	No
101033-44-7	Zirconium,tetrakis[2-[bis(2-hydroxyethyl)amino-kN]ethanolato-kO]-	Yes
21959-01-3	Zirconium(IV) chloride tetrahydrofuran complex	Yes
14644-61-2	Zirconium(IV) sulfate	Yes

17 Appendix II. Glossary

Adapted from (Colorado Oil and Gas Conservation Commission 2014a) and (FracFocus 2014).

Abandon	(1) The proper plugging and abandoning of a well in compliance with all applicable regulations, and the cleaning up of the wellsite to the satisfaction of any governmental body having jurisdiction with respect thereto and to the reasonable satisfaction of the operator.(2) To cease efforts to find or produce from a well or field.(3) To plug a well completion and salvage material and equipment.
Acid	A generic term used to describe a treatment fluid typically comprising hydrochloric acid and a blend of acid additives
ADP	Application for Development Permit: a permit to drill.
American Petroleum Institute (API)	The American Petroleum Institute is the primary trade association representing the oil and natural gas industry in the United States.

Annulus	The space between: (1) The casing and the wall of the borehole.(2) Two strings of casing.(3) Tubing and casing.
Aquifer	A water-bearing stratum of permeable rock, sand or gravel
Barrel	A unit of volume measurement used for petroleum and its products (7.3 barrels = 1 ton: 6.29 barrels = 1 cubic meter).
bbl	One barrel of oil; 1 barrel = 35 Imperial gallons (approx.), or 159 liters (approx.); 7.5 barrels = 1 ton (approx.); 6.29 barrels = 1 cubic meter.
bcf	Billion cubic feet; 1 bcf = 0.83 million tons of oil equivalent.
bcm	Billion cubic meters (1 cubic meter = 35.31 cubic feet).
Biocide	An additive that eliminates bacteria in the water that produce corrosive by-products
Blender	The equipment used to prepare the slurries and gels commonly used in fracture stimulation treatments
Borehole	The hole drilled into the earth
Breaker	An additive that reduces the viscosity of fluids by breaking long-chain molecules into shorter segments
CAS	Chemical Abstract Service
Casing	A steel tubular placed in a borehole
Casing	Pipe cemented in the well to seal off formation fluids or keep the hole from caving in.
Casing string	The steel tubing that lines a well after it has been drilled. It is formed from sections of steel tube screwed together.
Cement	A mixture of sand, water and a binding agent with no aggregates
Cement Bond Log	A geophysical log that graphically displays the bond between cement and casing
Clay stabilizer	An additive that prevents clays from swelling or shifting
Completion	The installation of permanent wellhead equipment for the production of oil and gas.

Condensate	Hydrocarbons which are in the gaseous state under reservoir conditions and which become liquid when temperature or pressure is reduced. A mixture of pentanes and higher hydrocarbons.
Conductor casing	The first casing string placed in a borehole. The purpose of conductor is to prevent the collapse of the hole in unconsolidated material such as soil
Corrosion inhibitor	An additivie used in acid treatments to prevent corrosion of tubulars by the corrosive treating fluid
Crosslinker	An additive that reacts with multiple-strand polymers to couple the molecules, creating a fluid of high but closely controlled viscosity
Crude Oil	Liquid petroleum as it comes out of the ground as distinguished from refined oils manufactured out of it.
Cubic foot	A standard unit used to measure quantity of gas (at atmospheric pressure); 1 cubic foot = 0.0283 cubic meters.
Cuttings	Rock chips cut from the formation by the drill bit, and brought to the surface with the mud. Used by geologists to obtain formation data.
Darcy's law	The mathematical equation which quantifies the ability of fluid to flow through porous material such as rock
Data van	The truck used to monitor all aspects of the hydraulic fracturing job
Development phase	The phase in which a proven oil or gas field is brought into production by drilling production (development) wells.
DOE	U.S. Department of Energy
Drill	(1)To bore a hole, Also see Drilling(2)An implement with cutting edges used to bore holes.

Drilling	The using of a rig and crew for the drilling, suspension, completion, production testing, capping, plugging and abandoning, deepening, plugging back, sidetracking, redrilling or reconditioning of a well (except routine cleanout and pump or rod pulling operations) or the converting of a well to a source, injection, observation, or producing well, and including stratigraphic tests. Also includes any related environmental studies. Associated costs include completion costs but do not include equipping costs.
Drilling rig	A drilling unit that is not permanently fixed to the seabed, e.g. a drillship, a semi-submersible or a jack-up unit. Also means the derrick and its associated machinery.
Dry hole	A well which has proved to be non-productive.
E&A	Abbreviation for exploration and appraisal.
E&P	Abbreviation for exploration and production.
Enhanced oil recovery	A process whereby oil is recovered other than by the natural pressure in a reservoir.
EPA	U.S. Environmental Protection Agency
EPCRA	Emergency Planning and Community Right to Know Act
Exploration drilling	Drilling carried out to determine whether hydrocarbons are present in a particular area or structure.
Exploration phase	The phase of operations which covers the search for oil or gas by carrying out detailed geological and geophysical surveys followed up where appropriate by exploratory drilling.
Exploration well	A well drilled in an unproven area. Also known as a "wildcat well".
Field	A geographical area under which an oil or gas reservoir lies.
Fishing	Retrieving objects from the borehole, such as a broken drillstring, or tools.
Formation pressure	The pressure at the bottom of a well when it is shut in at the wellhead.
Formation water	Salt water underlying gas and oil in the formation.

Frac tank	The container used to store water or proppant that will be used for hydraulic fracturing
Fracturing	A method of breaking down a formation by pumping fluid at very high pressures. The objective is to increase production rates from a reservoir.
Friction reducer	An additive used to reduce the friction forces on tools and tubulars in the wellbore
G	Gas.
G/C	Gas Condensate.
Gas field	A field containing natural gas but no oil.
Gas injection	The process whereby separated associated gas is pumped back into a reservoir for conservation purposes or to maintain the reservoir pressure.
Gas/oil ratio	The volume of gas at atmospheric pressure produced per unit of oil produced.
Gelling agent	An additive that increases the viscosity of a fluid without substantially modifying its other properties
Geographic Information Systems(GIS)	A computer system capable of assembling, storing, manipulating, and displaying geographically referenced information.
GIS	See: Geographic Information Systems
Groundwater	Water in the saturated zone in the subsurface
GWPC	Ground Water Protection Council
Hydrocarbon	A compound containing only the elements hydrogen and carbon. May exist as a solid, a liquid or a gas. The term is mainly used in a catch-all sense for oil, gas and condensate.
Hydrology	The study of the flow of water
Injection well	A well used for pumping water or gas into the reservoir.
Intermediate casing	A casing string sometimes used where needed for pressure control or additional isolation of formations such as coal.
IOGCC	Interstate Oil and Gas Compact Commission
Jacket	The lower section, or "legs", of an offshore platform.
Liquefied natural gas (LNG)	Oilfield or naturally occurring gas, chiefly methane, liquefied for transportation.

Liquefied petroleum gas (LPG)	Light hydrocarbon material, gaseous at atmospheric temperature and pressure, held in the liquid state by pressure to facilitate storage, transport and handling. Commercial liquefied gas consists essentially of either propane or butane, or mixtures thereof.
mboe	Million Barrels Oil Equivalent.
Mechanical Integrity Test	The act of setting a packer or retrievable bridge plug above the perforations in a wellbore and applying pressure to the annulus in order to ensure soundness of the casing.
Metric ton	Equivalent to 1000 kilos, 2204.61 lbs.; 7.5 barrels.
MIT	Mechanical Integrity Test
mmcfd	Millions of cubic feet per day (of gas).
MOU/MOA	MEMORANDUMS OF UNDERSTANDING/AGREEMENT
MSDS	Material Safety Data Sheet
Mud	A mixture of base substance and additives used to lubricate the drill bit and to counteract the natural pressure of the formation.
Natural gas	Methane CH4 (With or without impurities such as Nitrogen). Natural gas is often classified as either biogenic (of biological origin), or thermogenic (of thermal or heat origin)
Natural gas	Gas, occurring naturally, and often found in association with crude petroleum.
NGLs	Natural gas liquids. Liquid hydrocarbons found in association with natural gas.
NGWA	National Ground Water Association
O	Oil.
O&G	Oil and Gas.
Oil	A mixture of liquid hydrocarbons of different molecular weights.
Oil field	A geographic area under which an oil reservoir lies.
Oil in place	An estimated measure of the total amount of oil contained in a reservoir, and, as such, a higher figure than the estimated recoverable reserves of oil.

Operator	The company that has legal authority to drill wells and undertake the production of hydrocarbons that are found. The Operator is often part of a consortium and acts on behalf of this consortium.
Oxygen scavenger	An additive that prevents corrosion of tubulars by oxygen
Packer	A downhole device used in completions to isolate the casing-tubing annulus from the production conduit, enabling controlled production, injection or treatment.
Payzone	Rock in which oil and gas are found in exploitable quantities.
Permeability	A number expressed in darcies or millidarcies that describes the directional ability of a porous material to allow the flow of fluid. Rocks have vertical, horizontal and tangential permeability.
Permeability	The property of a formation which quantifies the flow of a fluid through the pore spaces and into the wellbore.
Petroleum	A generic name for hydrocarbons, including crude oil, natural gas liquids, natural gas and their products.
pH adjusting agent	An additive that adjusts the acidity/ alkilinity balance of a fluid
Platform	An offshore structure that is permanently fixed to the seabed.
Porosity	The percentage of void in a porous rock compared to the solid formation.
Possible reserves	Those reserves which at present cannot be regarded as âĂŸprobable' but are estimated to have a significant but less than 50% chance of being technically and economically producible.
Primary recovery	Recovery of oil or gas from a reservoir purely by using the natural pressure in the reservoir to force the oil or gas out.
Probable reserves	Those reserves which are not yet proven but which are estimated to have a better than 50% chance of being technically and economically producible.

Production casing	The casing string set near the bottom of a completed borehole through which oil or natural gas is produced
Proppant	Solid material such as Silica sand which is used to hold or "prop" open fractures
Proven field	An oil and/or gas field whose physical extent and estimated reserves have been determined.
Proven reserves	Those reserves which on the available evidence are virtually certain to be technically and economically producible (i.e. having a better than 90% chance of being produced).
Recomplete	An operation involving any of the following: (1) Deepening from one zone to another zone.(2) Completing well in an additional zone.(3) Plugging back from one zone to another zone.(4) Sidetracking to purposely change the location of the bottom of the well, but not including sidetracking for the sole purpose of bypassing obstructions in the borehole.(5) Conversion of a service well to an oil or gas well in a different zone.(6) Conversion of an oil or gas well to a service well in a different zone.
Recoverable reserves	That proportion of the oil and/gas in a reservoir that can be removed using currently available techniques.
Recovery factor	That proportion of the oil and/gas in a reservoir that can be removed using currently available techniques.
Reenter	To enter a previously abandoned well.
Reservoir	A bed of rock containing oil or natural gas
Reservoir	The underground formation where oil and gas has accumulated. It consists of a porous rock to hold the oil or gas, and a cap rock that prevents its escape.
Riser (drilling)	A pipe between a seabed BOP and a floating drilling rig.
Riser (production)	The section of pipework that joins a seabed wellhead to the Christmas tree.
Royalty payment	The cash or kind paid to the owner of mineral rights.
Saturated zone	The subsurface zone where the interstitial spaces of rock are filled with water

Secondary recovery	Recovery of oil or gas from a reservoir by artificially maintaining or enhancing the reservoir pressure by injecting gas, water or other substances into the reservoir rock.
Shale	A fine grained sedimentary rock that may contain oil or natural gas but which may not be producible naturally
Shut In Well	A well which is capable of producing but is not presently producing. Reasons for a well being shut in may be lack of equipment, market or other.
Shutdown	A production hiatus during which the platform ceases to produce while essential maintenance work is undertaken.
SI/TA	Shut In /Temporarily Abandoned
Sidetrack	A wellbore segment extending from a wellbore intersection along a wellbore path to a different wellbore bottomhole from any previously existing wellbore bottomholes.
Sidetracking	The well activity of drilling a new wellbore segment from a wellbore intersection to a new wellbore bottomhole or target.
Site	The location of a well including the area used for fluid storage and well treatment
Spring	The intersection of groundwater and surface water
Spud-in	The operation of drilling the first part of a new well.
Surface casing	The casing string set below fresh water aquifers to prevent their contamination
Surface Location	The location of a well or facility/measurement point.
Surface Reclamation	A restoration of the surface as for productivity or usefulness.
Surfactant	A chemical that acts as a surface active agent. This term encompasses a multitude of materials that function as emulsifiers, dispersants, oil-wetters, water-wetters, foamers and defoamers.
Suspended well	A well that has been capped off temporarily.
tcf	Trillion Cubic Feet (of gas).

Temporarily Abandoned	The act of isolating the completed interval or intervals within a wellbore from the surface by means of a cement retainer, cast iron bridge plug, cement plug, tubing and packer with tubing plug, or any combination thereof.
Toolpusher	Second-in-command of a drilling crew under the drilling superintendent. Responsible for the day-to-day running of the rig and for ensuring that all the necessary equipment is available.
Topsides	The superstructure of a platform.
Toxicology	The study of symptoms, mechanisms, treatment and detection of poisoning
TRI	Toxic Release Inventory
Tubing	A string of casing not typically cemented into a hole but which may be used to carry produced oil or natural gas from the subsurface
UIC	Underground Injection Control
Underground Injection Control	A program required in each state by a provision of the Safe Drinking Water Act (SDWA) for the regulation of Injection Wells, including a permit system. An applicant must demonstrate that the well has no reasonable chance of adversely affecting the quality of an underground source of drinking water before a permit is issued.
Unsaturated zone	The subsurface zone where the interstitial spaces of rock contain but are not completely filled with water
Vadose zone	The subsurface zone between the surface and the unsaturated zone through which water travels
Variable Density Log	The geophysical log the is a graphic representation of the bond between the cement and the borehole
Well log	A record of geological formation penetrated during drilling, including technical details of the operation.
Wellbore	See borehole
Workover	Remedial work to the equipment within a well, the well pipework, or relating to attempts to increase the rate of flow.

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