

Pits versus Tanks:
Risks and Mitigation
Options for On-site
Storage of Wastewater
from Shale Gas
and Tight Oil
Development

Yusuke Kuwayama, Skyler Roeshot, Alan Krupnick,
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Abstract

In this paper, we summarize findings from a research effort aimed at understanding the sources of risk associated with on-site shale gas and tight oil wastewater storage in the United States, the gaps that exist in knowledge regarding these risks, policy and technology options for addressing the risks, and the relative merits of those options. Specifically, we (a) identify the potential risks to human and ecological health associated with on-site storage of shale gas and tight oil wastewater via a literature survey and analysis of data on wastewater spills, (b) provide a detailed description of government regulations or industry actions that may mitigate these risks to human and ecological health, and (c) provide a list of recommendations specific to wastewater storage that may help generate progress toward concrete action to make shale gas and tight oil development more sustainable and more acceptable to a skeptical public, while keeping costs down.

Key Words: oil and gas production, wastewater storage, environmental regulation

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1. Introduction

In 2013, Resources for the Future (RFF) released the results of a survey of four key stakeholder groups in shale gas development—industry, regulators, nongovernmental organizations (NGOs), and academics—to find common ground about which of 264 possible “risk pathways” are top priorities for further government regulations or industry voluntary actions. This project identified 15 consensus high-priority pathways that were common across all four stakeholder groups. RFF characterized these as “pathways to dialogue,” areas in which stakeholders can find common ground and, ideally, unite behind effective steps to minimize risk.

In this survey, the risk pathway that was most often selected by the stakeholder groups is on-site pit storage of flowback and produced water constituents and the potential for leakage into surface water. This option was the most frequently chosen pathway by industry, regulators, and academics and the fourth most often selected pathway by NGO respondents. In addition to concerns regarding surface water, the risk to groundwater resources generated by on-site pit storage of flowback and produced water constituents was also a pathway that was common to all groups’ top 10 most selected pathways (Krupnick and Gordon 2015).

In light of this consensus regarding the need for further government regulations or industry voluntary actions in this area, RFF has developed a research effort that aims to better understand the sources of risk associated with on-site shale gas wastewater storage in the United States, the gaps that exist in knowledge regarding these risks, policy and technology options for addressing the risks, and the relative merits of those options. The research effort also addresses the storage of wastewater from tight oil development, which exhibits similar production

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technologies, industry practices, regulatory contexts, and environmental challenges. This report summarizes our findings from this research. Specifically, the following are the main objectives of this report:

- identify the potential risks to human and ecological health associated with on-site storage of shale gas and tight oil wastewater via a literature survey and analysis of data on wastewater spills;
- provide a detailed description of government regulations or industry actions that may mitigate these risks to human and ecological health; and
- provide a list of recommendations specific to wastewater storage that may help generate progress toward concrete action to make shale gas and tight oil development more sustainable and more acceptable to a skeptical public, while keeping costs down.

Our study focuses on the risks and risk mitigation options associated with on-site storage of flowback, produced water, and other types of wastewater generated during shale gas and tight oil development (including the drilling, completion, hydraulic fracturing, and production stages) prior to recycling or disposal.

Existing literature on the risks and mitigation options associated with wastewater storage is scarce, and information on technologies and practices used specifically in shale gas and tight oil operations is even scarcer. An important contribution of this report is to bring together this information into one comprehensive resource. We supplement this literature review with information gained from a search of existing state regulations, an analysis of state databases on environmental incidents from oil and gas operations, an informal survey of some members of the Independent Petroleum Association of America (IPAA), and feedback from staff at state regulatory agencies.

Our analysis of wastewater pits is complicated by the fact that different types of pits are used to store wastes from different stages of oil and gas development. The State Review of Oil and Natural Gas Environmental Regulations (STRONGER) employs the following classification of pit types as a guideline for regulatory programs (STRONGER 2015):

1. **Reserve pits** are used to store additional drilling fluids for use in drilling operations and/or to dispose of wastes generated by drilling operations and initial completion procedures.
2. **Production pits**, which include the following sub-types of pits:

- a. **Skimming or settling pits** are used to allow for settling of solids and separation of residual oil;
 - b. **Produced water pits** are used for storage of produced water prior to injection for enhanced recovery or disposal, off-site transport, or surface-water discharge.
 - c. **Percolation pits** are used to dispose of waste liquids via drainage or seepage through the bottom and/or sides of the pits into surrounding soils.
 - d. **Evaporation pits** are used to contain produced waters which evaporate into the atmosphere
3. **Special purpose pits**, including **blowdown pits**, **flare pits**, **emergency pits**, **basic sediment pits**, and **workover pits**.¹

Distinguishing between these pit functions is important because states may impose different regulations or permitting requirements based on pit type. For example, Texas regulates short-term pits (e.g., reserve pits) differently from long-term pits (e.g., produced water pits). Likewise, Pennsylvania's rules differentiate between temporary pits used during drilling and hydraulic fracturing, produced water pits, and centralized impoundments that unconventional gas operators use to store fluids from multiple well sites. To complicate matters further, there is differing nomenclature across regulators and stakeholders for referring to each type of pit. States vary in the number of pit classifications, ranging from 3 in West Virginia to 21 in Texas. Further, some experts distinguish between *pits* and *impoundments*, with the latter term tending to refer to storage options of a more temporary nature. However, we did not find this distinction to be commonplace in existing state regulations.²

Enclosed, portable tanks are a commonly used alternative to pits for the storage of wastewater. A typical tank in a shale gas or tight oil operation consists of a 21,000-gallon, V-bottom rectangular tank that can be pulled by a semi-truck (URS Corporation 2011). Alternative designs may involve larger volumes or cylindrical bottoms instead of V-bottoms, and some

¹ Blowdown pits are used for collecting material resulting from the emptying or depressurization of wells or vessels. Workover pits are used to contain liquids during remedial operations on a producing well in an effort to increase production (STRONGER 2015).

² The lack of standardized nomenclature for distinguishing between pits and impoundments may constitute a regulatory gap if wastewater storage in impoundments poses risks similar to those of storage in pits, but oil and gas operators implement different safeguards for the two types of storage.

operators use modified grain bins as storage tanks (Apache Corporation 2014). Hoses can be used to connect (“gang”) several tanks together, allowing for variable capacity. The use of tanks as a wastewater storage solution has been increasing in the oil and gas industry and has been a target for new regulations, including the final standards released by the US Department of the Interior’s Bureau of Land Management (BLM) in 2015 for hydraulic fracturing on public and tribal lands. Therefore, it is important to identify the risks associated with tanks and compare them with the risks associated with pits. We undertake such a comparison in this report based on information from state databases on spills from pits and tanks, as well as on feedback collected from stakeholders and state regulators.

Our report proceeds as follows. Section 2 below summarizes our literature review on the risks of on-site shale gas and tight oil wastewater storage, including an overview of existing knowledge regarding the chemical composition of wastewater that is generated from hydraulic fracturing, possible types of contaminant release mechanisms, exposure pathways, and potential impacts to human and ecological health. Section 3 describes our analysis of state databases on environmental incidents from oil and gas operations, focusing on three states for which records for spills and releases from wastewater pits and tanks are available: New Mexico, Colorado, and Oklahoma. Section 4 describes existing and potential future regulatory or industry voluntary options for mitigating the risks associated with storage of flowback and produced water. We also compare the number and stringency of these regulatory elements across states. In Section 5, we describe methods that can allow for the estimation of the costs and benefits of the risk mitigation options and provide such estimates when they are available in the literature. Section 6 concludes the report with a list of recommendations for cost-effective approaches to address the risks associated with wastewater pits and tanks.

2. Risks to Human and Ecological Health: A Review of the Literature

While pits and tanks have been instrumental in providing for on-site, temporary storage of flowback, produced water, and other fluids at oil and gas production sites, there have been long-standing concerns that these storage solutions for contaminated wastewater may allow the release of harmful substances and ultimately lead to human and ecological exposures. Research efforts to characterize releases from pits and tanks were made well before hydraulic fracturing and horizontal drilling technologies unlocked large gas reserves in shale deposits across the country. Our review of the literature covers relevant studies from academic journals, government agencies, and other organizations, including consulting firms, industry engineers, trade groups, and nonprofit organizations. The research in this area is sparse, and we found few studies

regarding human and ecological health risks. However, impacts are still possible, and we do our best to classify these potential health effects below.

Although storing drilling muds, fracturing fluids, and produced water in pits and tanks is a common practice, these wastes are not intended to be released directly into the environment. Thus it is important to understand the processes by which humans and ecosystems may be exposed to contaminants contained in these wastes. Describing the risks to human and ecological health from shale gas and tight oil wastewater storage requires breaking down these exposure processes into three main components:

1. the chemical composition of wastewater from hydraulic fracturing that is stored in pits and tanks;
2. the mechanisms by which the chemicals in wastewater stored in pits and tanks are released into the environment; and
3. the pathways through which humans and ecological systems are exposed to the chemicals that are released from pits and tanks.

These processes are summarized in Figure 1, which illustrates how wastewater storage options, potential release mechanisms, and potential exposure pathways are related to the way in which fluids and wastewater are handled within shale gas and tight oil production. In addition to initially storing the fluids in pits and tanks, they may be trucked directly offsite or treated and recycled. Ultimate disposal may take place by using Class II deep injection wells or transporting the fluids to municipal and commercial waste treatment plants, which then release the treated wastewater (if any) to rivers and streams.³ Chemicals may be released into the environment if fluids contained in pits and tanks are transported to a wastewater treatment plant that is unable to fully remove the contaminants before discharging the treated wastewater into a surface water body. Although previous studies have found evidence of this problem (Olmstead et al. 2013), we do not address this particular release mechanism in our report because the required mitigation options are not associated with wastewater storage in pits or tanks per se. We also do not address the risks associated with disposal of wastewater after storage via road spreading or injection into deep wells, nor do we address risks associated with the transportation stage itself. Finally, we do

³ On April 7, 2015, EPA published proposed pretreatment discharges of wastewater pollutants from onshore unconventional oil and gas extraction facilities, including a prohibition of discharges to publically owned treatment works (POTWs). EPA is also in the process of reviewing discharges to private wastewater treatment facilities.

not address potential exposure that results from landfill disposal of solid wastes generated from the wastewater treatment process.

Our analysis of the literature shows that there are three primary mechanisms by which contaminants may be released from wastewater stored in pits and tanks: (1) volatilization processes, whereby contaminants dissolved in water held in pits are vaporized; (2) surface spills of fluids and potential subsequent surface runoff into lakes, rivers, and streams; and (3) leaching of contaminants through permeable soils into groundwater. Furthermore, contaminants may move from one medium (air, surface water, groundwater, or soil) to another after they are released from a pit or tank. Ultimately, humans and ecological systems are exposed to these releases via inhalation, dermal uptake, or ingestion.

2.1. Chemical Composition of Wastewater from Hydraulic Fracturing

Several studies address the potential health impacts of pollutants in industrial wastewater, but only some refer specifically to oil or gas production using hydraulic fracturing. In a survey of industrial surface water impoundments conducted in the early 2000s, few were found to contain concentrations of harmful chemicals that exceed standard human health benchmarks (Johnson et al. 2003; EPA 2001). More recently, based on a compilation of 944 products containing 632 chemicals used during the drilling and hydraulic fracturing stages, Colborn et al. (2011) find that more than 75 percent of the chemicals could affect the skin, eyes, and other sensory organs, as well as the respiratory and gastrointestinal systems. The authors also found that 40 to 50 percent of the chemicals could affect the nervous, immune, cardiovascular, and renal systems; 37 percent could affect the endocrine system; and 25 percent could cause cancer and mutations. Esswein et al. (2014) found airborne concentrations of chemicals that potentially pose health risks for workers in the natural gas sector, depending on the length of exposure. Note our use of the word *could*—while many chemicals are toxic if a human is exposed to them in high enough concentrations or for a long enough period of time, actual human health risks may (or may not) be *de minimis*.

In this spirit, based on our analysis of existing literature, we identify five major categories of potentially toxic substances commonly found in oil and natural gas waste pits and tanks that could result in negative human health and ecological effects at high enough doses:

1. volatile organic compounds (VOCs);
2. metals;
3. total dissolved solids (TDS);

4. naturally occurring radioactive material (TENORM); and
5. oil.

We discuss the risks of each of these substance categories below. When possible, we provide information on the presence of these substances in shale gas and tight oil wastewater and compare their measured concentrations with levels that are known to generate adverse health risks and violate public health goals. It is important to note that the measured concentrations presented below apply to specific shale plays and may not be representative of wastewater produced elsewhere. The chemical characteristics of produced fluids vary greatly among states, regions, plays, and formations, and as a result, some of these substance categories may not be of significant concern for some shale plays.

2.1.1. Volatile Organic Compounds (VOCs)

The volatile organic compounds (VOCs) commonly found in shale gas and tight oil wastewater are benzene, toluene, ethylbenzene, and xylenes, collectively referred to as BTEX (Havics and Wright 2011). BTEX are present at low concentrations in crude oil and are also found in coal and gas deposits (Gross et al. 2013). During the drilling and hydraulic fracturing process, these chemicals can be brought to the surface with flowback and produced water and subsequently stored in pits and tanks. These chemicals can easily volatilize into the air and negatively affect air quality near pits. At sufficient doses, BTEX are known to have negative human health impacts. For example, benzene is known to affect the hematological (blood forming), immune, and nervous systems and is also a known carcinogen. Toluene affects the cardiovascular and nervous system. Ethylbenzene can cause kidney damage, is known to cause hearing loss and damage to the inner ear in animals exposed to relatively low concentrations, and is classified as a possible human carcinogen. Finally, xylenes can affect the respiratory system and cause liver and kidney damage (ATSDR 2007).

The second and third columns in Table 1 summarize data obtained from a study by the Pennsylvania Department of Environmental Resources and from RFF research quantifying concentrations of VOCs present in oil and gas wastewater (Gilius et al. 1994; Shih et al. 2015). In order to get a sense of whether these ranges of VOC concentration are a cause for concern, we

refer to the Minimum Risk Levels (MRLs) List compiled by the Agency for Toxic Substances and Disease Registry (ATSDR).⁴

ATSDR's MRL List provides, for various substances, an estimate of daily human exposure that is "likely to be without appreciable risk" of adverse noncancer health effects over a specified duration of exposure (ATSDR 2013). The fourth column in Table 1 provides the MRLs for oral exposure to the VOCs measured in oil and gas wastewater by the same two studies. These MRLs are expressed in terms of milligrams per kilogram per day (mg/kg/day) and, depending on the substance, are derived for acute (1 to 14 days), intermediate (15 to 364 days), and chronic (365 days and longer) exposure durations. Given these units, in order to get a sense of whether direct ingestion of wastewater could lead to human health risks, the MRL needs to be multiplied by the weight of the individual (equal to 65 kilograms for the average adult human) and divided by the volume of the wastewater ingested in a day. The Superfund Exposure Assessment Manual (SEAM) estimates that a human adult incidentally ingests 50 milliliters/hour of water while swimming and ingests 2 liters/day of drinking water in his or her daily life (EPA 1989). These figures imply, for example, that an average adult ingesting 1 liter of Pennsylvania oil and gas wastewater per day on a chronic basis could be at significant health risk based on benzene concentrations alone.

In addition, the concentration of VOCs measured in oil and gas wastewater by the two studies can be compared with the figures in the fifth column in Table 1, which lists the Maximum Contaminant Level Goals (MCLGs) for each substance as determined by EPA's National Primary Drinking Water Regulations. These levels in drinking water are below those in which there is no known or expected risk to health and serve as EPA's nonenforceable public health goal.

It is important to note that the characterization of health risk described above is only illustrative and is not linked to actual levels of exposure. It is highly unlikely that individuals will directly swim in or drink the wastewater contained in pits and tanks. As wastewater in pits leaks

⁴ ATSDR is the US federal government body within the Department of Health and Human Services that provides science-based health information to prevent harmful exposures to toxic substances. The ATSDR is charged under the Comprehensive Environmental Response, Compensation, and Liability Act of 1990 (CERCLA), commonly known as the Superfund Act, to assess the presence and nature of health hazards at specific Superfund sites. Furthermore, under the amendments to the Resource Conservation and Recovery Act of 1976 (RCRA), the ATSDR conducts public health assessments of hazardous waste storage and destruction facilities when requested by the Environmental Protection Agency (EPA) and assists EPA in determining which substances should be regulated and the levels at which substances may pose a threat to human health.

into water sources and evaporates into the air, VOC concentrations are likely to be diluted, and actual human intake is likely lower than the range detected in actual pits.⁵ On the other hand, the sample calculation above does not account for additional adverse effects that may result from interactions between VOCs and between VOCs and other potentially toxic substances once exposure takes place.

2.1.2. Metals

Metals are the most common class of chemicals found in industrial impoundments (Johnson et al. 2003). Like VOCs, different metals are distributed throughout geologic formations, and drilling and hydraulic fracturing causes these metals to migrate to the surface with flowback and produced water. Table 2 provides a summary of metal concentrations associated with wastewater analyzed in the aforementioned studies in Pennsylvania (Gilius et al. 1994; Shih et al. 2015), accompanied by MRLs and MCLGs for each metal. The RFF study indicates that barium is particularly prevalent in produced water from Marcellus Shale gas development (Shih et al. 2015). Depending on the dose, daily human intake of these metals can have many negative short- and long-term health impacts, including cancer risk, respiratory damage, gastrointestinal issues, and cardiovascular damage.

2.1.3. Total Dissolved Solids (TDS)

Produced water that comes to the surface after hydraulic fracturing contains high concentrations of total dissolved solids (TDS) as a result of salt in the ancient oceans and other inorganic constituents present in geologic rock formations located in areas where water is in contact (USGS 2015). The presence of inorganic constituents varies greatly depending on the formation (Benko and Drewes 2008).

Brine is defined as water having a TDS concentration greater than 35,000 milligrams per liter (mg/L). Brine leaks and spills from pits and tanks can harm soils, leaving barren salt scars, and can negatively impact wetlands. Most freshwater organisms are impaired or die with exposure to salinity levels greater than 10,000 mg/L, and high TDS concentrations can limit the growth of plants and invertebrate species (Gleason and Tangen 2014). Wastewater effluent standards in Pennsylvania are set at 500 mg/L for TDS and 250 mg/L for chloride, although chloride and some other soluble constituents are poorly removed by wastewater treatment plants unless they employ desalinization technologies. Shih et al. (2015) find that average TDS

⁵ Evidence on release and exposure mechanisms for these substances is covered in Section 2.2 below.

concentrations in produced water in Marcellus Shale gas wastewater are around 88,000 mg/L; this figure can be compared with that of ocean water, which is around 30,000 mg/L.

2.1.4. Naturally Occurring Radioactive Material (TENORM)

Naturally occurring radioactive material (NORM) is found throughout natural geologic formations and may be transported to the surface in produced water that is stored in pits. Previous research suggests that 226 radium and 228 radium (both gamma-emitting radionuclides), which have half-lives of 1,600 years and 5.8 years, respectively, are the most common radionuclides found in reserve pits (Rich and Crosby 2013). However, this research also finds elevated levels of alpha-, beta-, and gamma-emitting radionuclides in fluids stored in active reserve pits and in soil of vacated reserve pits. The potential release of radon gas into the atmosphere when produced water is brought to the surface is also a concern. NORMs are considered “technologically enhanced” (TENORMs) when their concentrations are increased by human practices (CRCPD 2003). TENORMs may be present in pipe scale or in filter socks, and as such may be more of a concern than NORMs present in produced water and drilling fluid that are stored in pits and tanks.

Depending on the isotope and the concentration, different forms of radiation are associated with a variety of negative human health effects, such as cell damage, anemia, nervous system disorders, fetal congenital disorders, and cancer risk. Radiation can also be taken up by soil and crops that are then used to feed livestock, further increasing human exposure through meat and milk products (Rich and Crosby 2013).

2.1.5. Oil

Oil is often present in pits and tanks either because oils are present in the geologic formation and are transported to the surface with flowback and produced water during the hydraulic fracturing process, or because the oil and grease used on fracking equipment is being washed off and disposed of in these pits and tanks. Shih et al. (2015) find oil and grease concentrations of about 10 mg/L in fracking fluid wastes in Pennsylvania. This concentration can pose a risk to wildlife, particularly avian wildlife that is attracted to pits (Ramirez 2009). If a pit spill or leak occurs, these substances can also cause harm to soils, aquatic systems, and drinking water.

2.2. Contaminant Release and Exposure Mechanisms

The presence of volatile organic compounds (VOCs) increases the risk of contaminant release through airborne vapors. Factors that affect the volatilization of a chemical from the

water surface of a pit or tank and its subsequent transport in the atmosphere include the properties of the chemical, the concentration and mass of the chemical, the temperature of the air above the pit or tank and that of the wastewater, wind speed, and characteristics of the impoundment such as its surface area (Johnson et al. 2003).

Two recent studies have examined the potential for harmful chemical exposure associated with pits and tanks from the perspective of worker safety. Bloomdahl et al. (2014) assessed worker exposure and resulting health risks for 12 VOCs present in flowback water stored in open-air pits in the Marcellus Shale, using models of volatilization to estimate fluxes from aqueous phase to gas phase concentrations. These gas phase concentrations were, in turn, used to estimate worker exposure. The authors find that their models do not demonstrate an increased risk of adverse effects due to temporary exposure at mean concentration values for the 12 VOCs as indicated by hazard quotients, hazard indices, or excess lifetime cancer risks.⁶ However, the authors do find that 97.5 percentile concentration values lead to a hazard index of 1.0, which is the highest level at which adverse noncancer health effects are not likely to result over a lifetime of exposure. The authors also warn that low wind conditions near the flowback pits may increase human health risks through air exposures to VOCs.

Esswein et al. (2014) obtained real-time measurements of airborne benzene at a variety of point sources, including headspace (the unfilled space in a tank) or immediately outside hatches of flowback and production tanks, and found that concentrations can potentially pose health risks to workers based on criteria established by the National Institute for Occupational Safety and Health (NIOSH) and the American Conference of Governmental Industrial Hygienists (ACGIH), particularly for flowback technicians who gauged tanks. However, this study did not examine actual worker health outcomes, and we are not aware of any existing studies that have conducted such assessments.

There is generally a decline in the concentration of airborne chemicals as the distance from a source increases. In a survey of 4,500 facilities that include surface impoundments, EPA finds that the majority of those impoundments posed no air inhalation risk of concern for the closest residents (based on locations reported in surveys or through US Census information). An estimated 4 to 5 percent of impoundments had a risk of concern for nearby residents; a facility was deemed to exceed a risk criterion if constituents implied a cancer risk of one or more in

⁶ A hazard quotient is the ratio of the dose of contaminant expected at an exposure point to an appropriate safe reference dose.

100,000 or a hazard quotient greater than one for noncancer effects. An additional 4 to 8 percent of facilities did not pose air inhalation risks but did generate releases that exceed health-based levels at a distance of 25 meters from the facilities (EPA 2001; Johnson et al. 2003).⁷ In a separate study that specifically addressed natural gas producers, the Garfield County Department of Public Health collected ambient air samples at each cardinal direction along four well pad perimeters in rural Garfield County, Colorado, during well completion by four different companies in summer 2008 (McKenzie et al. 2012). The highest hydrocarbon levels corresponded to samples collected directly downwind of flowback collection tanks vented directly into the air, while the lowest hydrocarbon levels corresponded to either background samples or samples collected upwind of the flowback tanks. The noncancer risks associated with these air emissions were driven by exposure to trimethylbenzenes, aliphatic hydrocarbons, and xylenes, all of which have neurological or respiratory effects, and the cancer risk was driven by the presence of benzene.

Surface spills due to overtopping of pits can result in contamination of adjacent surface water bodies through overland transport of wastewater (Entrekin et al. 2011; EPA 2001). Spills on the surface can also be caused by tanks that are used to hold wastewater if the tank overflows or develops a leak. Such incidents are more likely during storm events when there is excessive precipitation, when dike or berm systems fail, or when pits and tanks are overfilled with wastewater due to human error or equipment malfunction (GAO 2012; Johnson et al. 2003; EPA 2001). Evidence of surface spills occurring in oil and gas operations can be found in state databases on environmental incidents, described in Section 3 below.

EPA's recent assessment of the potential impacts of hydraulic fracturing for drinking water resources cites two retrospective case studies that found potential surface water and groundwater impacts (EPA 2015). One of the studies found elevated chloride concentrations and timing relative to historical data that suggested groundwater impact to a private water well in southwestern Pennsylvania due to a nearby pit, although evaluation of other water quality parameters did not provide clear evidence of flowback or produced water impacts. The other study, conducted in Wise County, Texas, found impacts to two water wells that were attributed to brine. However, the data collected for the study were not sufficient to distinguish among four possible sources, one of which was leaks from reserve pits and/or impoundments.

⁷ The specific health-based levels for each chemical can be found in Table 3 of Johnson et al. (2003).

Leaching of contaminants through permeable soils into groundwater is also a concern. The aforementioned EPA study on industrial surface impoundments estimates that only 1 percent of facilities in the United States had one or more impoundments that were predicted to have risks because of groundwater contamination at drinking water wells. Two main determinants of the potential for contaminant release to and movement through the subsurface is the presence of a pit liner and the depth to groundwater. The role of pit liners in limiting the environmental release of oil and gas wastewater is discussed in Section 4.3, and the analysis of state databases on environmental incidents reveals several cases of pit liner failure. An additional concern with leaching of contaminants into groundwater is that the groundwater may be hydrologically connected to a surface water body, potentially leading to exposures via contact with rivers, streams, and lakes.

In summary, existing studies on contaminant releases from pits and tanks provide evidence that, at least in some cases, exposure to substances in shale gas and/or tight oil wastewater through airborne vapors has been sufficient to entail risks to human health, especially for workers involved in flowback operations. Exposure mechanisms have been most clearly identified for VOCs, particularly benzene. However, the lack of evidence on risks from contaminants other than VOCs may be due the absence of studies that focus on these contaminants. In addition, the lack of evidence on contaminant exposure as a result of surface spills and leaching into groundwater may also be due a lack of studies that focus on these mechanisms. Because state databases on environmental incidents in the oil and gas sector do contain instances of surface spills and pit liner failure, further research is needed to determine whether such releases can lead to exposures that incur risks to human health. Furthermore, our literature review did not find any studies that rigorously addressed potential impacts on ecosystem health that are directly linked to wastewater storage in pits or tanks.

3. State Databases of Spills and Releases from Pits and Tanks

Most of the major energy-producing states have reporting requirements that allow for the tracking of spills and releases caused by oil and gas operations. Although many of these reports can be accessed online, these websites often do not possess the functionality to easily narrow down the recorded incidents to those that are associated with pits and tanks. One exception is the website for New Mexico's Oil Conservation Division (OCD), which allows users to generate

summary tables after specifying the spill source type.⁸ We provide an analysis of these spill data below. In addition, we provide a partial analysis of spill and release reports made available by the Colorado Oil and Gas Conservation Commission (COGCC), which we downloaded individually and examined manually,⁹ and a summary of fluid releases reported to the Oklahoma Corporation Commission (OCC) as compiled by Fisher and Sublette (n.d.). Although the time period covered by the data from these three states includes earlier years during which hydraulic fracturing was not yet commonplace, we feel that analysis of these incidents is informative because some current wastewater storage practices are similar to those employed during the pre-fracking period.

3.1. New Mexico

According to the spills database made available by New Mexico's Oil Conservation Division (OCD), between 2000 and 2014, a total of 106 spills were reported where pits were specified as the spill source, and a total of 62 spills were reported where tanks were specified as the spill source.¹⁰ Figure 2 below illustrates the number of spills that were reported in each year from the two storage types. While the number of reported spills from tanks remained fairly stable over this time period, the number of reported spills from pits increased up to 2006 and decreased thereafter. While this information on the number of spills over time is informative, New Mexico does not provide data on the total number of pits and tanks in use at any given time, and as a result, we are not able to assess risks based on an understanding of the *relative* frequency and size of spills.¹¹

Figure 3 depicts the distribution of fluid volumes associated with the spills from pits. The figure reveals that the distribution of volumes spilled is skewed to the left; that is, most spills are relatively small, but there are also some outliers involving very large volumes. The largest spill that is recorded in the database involved 10,000 barrels of fluid (1 barrel is equivalent to 42 gallons), while the average and median volumes across spills were 413 barrels and 40 barrels,

⁸ The New Mexico Oil Conservation Division spills database can be accessed at <https://wwwapps.emnrd.state.nm.us/ocd/ocdpermitting/Data/Incidents/Spills.aspx>.

⁹ Spill/release reports filed with the Colorado Oil and Gas Conservation Commission can be accessed at <http://cogcc.state.co.us>.

¹⁰ The database includes additional spills during this time period that have a reported volume equal to zero.

¹¹ Assuming that New Mexico has the same number of pits as tanks, spills are 71 percent more likely to occur from pits than from tanks.

respectively. Figure 4 illustrates the distribution of spills that are 200 barrels or less in volume, which constitute about 80 percent of all the spills. Even within this more limited range, the distribution of spill sizes is significantly skewed to the left.

Figure 5 depicts the distribution of fluid volumes *lost* from pits—that is, the volumes of the portions of spills not recovered by the pit operators. The figure reveals a similar pattern to that of spill volumes; the volume of fluid lost during spills is often relatively small, but in a small number of cases very large volumes have been lost. Figure 6 illustrates the distribution of loss volumes for spills that are 200 barrels or less in volume, constituting 83 percent of all the spills.

Figures 7 through 10 provide the same information as Figures 3 through 6 for spills that have been reported from tanks. The patterns that are observed in terms of spill sizes for pits are also present for tanks, although the absolute spill volumes are generally much smaller for tanks. Although there were less than twice as many spills from pits as from tanks, pits lost over 10 times more fluid over the study period. Overall, the average spill size from tanks is equal to 112 barrels, with a median spill size of 36 barrels. That spill sizes are smaller for tanks than for pits is not surprising, given the smaller storage capacities associated with tanks.

Figures 11 and 12 summarize the relationship between volumes spilled and volumes lost from pits (for spills less than 200 barrels) and tanks (for spills less than 100 barrels). The clustering of points along the x-axes and the 45-degree lines in these graphs indicates that most spills are recovered either completely or not at all; relatively few spills are partially recovered.

Examination of these New Mexico data also revealed differences in the materials that tend to be spilled from pits and tanks. Table 3 provides information on the frequency and sizes of spills from pits when categorized by material spilled. The most commonly spilled fluids were, in order of decreasing frequency, produced water, drilling mud or fluid, brine water, and crude oil. Brine water spills from pits, while not as frequent as spills involving other fluids, added up to the largest total spill volume. Tanks exhibited a greater diversity of materials spilled, including fresh water, frac fluid, hydrochloric acid, and potassium chloride, in addition to the crude oil, produced water, brine water, and drilling mud/fluid that also tend to be spilled from pits.

The OCD website also contains data on the causes of spills. Table 4 provides information on the frequency and sizes of spills from pits when categorized by spill cause. These statistics show that overflowing of the pit and liner malfunction are by far the most common causes of spills in New Mexico. Reading the comments sections associated with each spill report entry in the database, we found that overflow incidents are usually caused by excessive rain, equipment failure, or human error, while liner malfunctions are commonly a result of excessive pressure on

the liner, tears and holes in the liner, or inadequate liner welds. Table 4 also categorizes spills from tanks by spill cause. For tanks, leaks are the single most common cause of spills, and the comments sections indicate that these leaks usually result from seals and gaskets that crack or failure of end caps, valves, or couplings. Other common tank spill causes include overfilling (often due to human error on the part of truck drivers), tank collapse, lightning strikes, and vandalism. Finally, it is important to note the relatively large number of unidentified or undocumented losses (26 out of 106 for pits, 11 out of 62 for tanks), which points toward a need for improved reporting and record-keeping procedures.

3.2. Colorado

Although the Colorado Oil and Gas Conservation Commission (COGCC) provides a comprehensive set of spill and release reports online, the limited search functionality of the commission's website makes it difficult to summarize all of the incidents that have occurred involving pits and tanks. In order to start characterizing the nature of spills from pits and tanks in Colorado, our strategy was to examine the 50 largest spills that occurred between June 2010 and May 2014, where the size of the spill was based on spill area. Of these 50 largest spills, 18 were spills from pits and 9 were spills from tanks (which are variously described as raw water tanks, frac tanks, or produced water tanks on COGCC spill/release reports). As was the case with New Mexico, the majority of spills from pits were caused by liner malfunctions; 14 reports contain references to compromised pits, while the root causes of the remaining 4 pit spills are not specified. All but one of the 9 tank spills were due to overflows. According to the reports, materials spilled included oil, water, produced water, and flowback water.

Gross et al. (2013) manually extracted data from the COGCC database for all surface spills with reported groundwater impacts in Weld County between July 1, 2010, and July 1, 2011. Thirty-eight of the 77 surface spills with groundwater impacts originated from tank battery systems, while none of the spills were reported to be associated with pits. Groundwater samples taken from the spill excavation area for all 77 spills were analyzed for the four components of BTEX (benzene, toluene, ethylbenzene, and xylene) and were found to exceed national drinking water maximum contaminant levels (MCLs) in 90, 30, 12, and 8 percent of the samples, respectively. However, the authors also find that remediation was effective at reducing BTEX levels for 84 percent of the spills based on COGCC requirements. According to COGCC staff, there are currently no pits used to store flowback fluids or produced water from the development of the Niobrara Shale in Weld County; flowback is generally contained in tanks and the only pits permitted in Weld County in the primary area of shale development are lined freshwater pits used during the drilling and completion phases.

3.3. Oklahoma

Fisher and Sublette (n.d.) provide a summary of fluid releases that were reported to the Oklahoma Corporation Commission (OCC) during the 10-year period from 1993 to 2003. Although this time period precedes the large increase in the use of hydraulic fracturing in US natural gas production, it is still informative to examine the characteristics of spills during this period because the design of pits and tanks has not changed significantly. The reports to the OCC are very detailed, specifying release volumes, sources, and causes, as well as any resulting environmental damages. Based on these reports, the authors estimate that exploration and production (E&P) operations in Oklahoma during this time period released 620,025 barrels of crude oil and 1,440,154 barrels of saltwater. Although the average size of oil spills remained relatively constant, the authors argue that releases of both oil and saltwater had actually increased relative to the total volume of oil produced because of the decline in oil production in Oklahoma. This suggests, unsurprisingly, that production is a poor proxy for spill likelihood or size; the number of wells completed would likely be a better proxy.

For spills from identified sources for which the release volume was quantified, pits had the highest median oil release volume, at 34 barrels, followed by tanks at 30 barrels. As a result, the median volume of oil spills from pits exceeds that of releases from all other sources, which consist of surface equipment, lines, and wells. Likewise, pits and tanks are associated with the highest median release volume for saltwater, at 81 barrels and 48 barrels, respectively. Overall, tanks accounted for 47 percent of total estimated volume of oil releases, while pits accounted for 5 percent. Tanks accounted for 31 percent of total estimated volume of saltwater releases, while pits accounted for 4 percent. Unfortunately, an estimate of the total number of pits and tanks used during this period in Oklahoma is not provided, making these statistics difficult to interpret. Pits were probably more prevalent than tanks during this earlier time period, which would imply that oil and saltwater were more likely to spill from a tank than from a pit.

While Fisher and Sublette (n.d.) report summary data concerning the cause of oil and saltwater releases, they do not separate the data by the type of spill source. Overflows were the most frequently reported cause of releases for both oil and saltwater (81 percent and 54 percent, respectively), and the authors hypothesize that most of these overflows occurred from tanks. Illegal activity, which includes theft, vandalism, and dumping, caused 5 percent of all oil releases and a surprising 24 percent of all saltwater releases. Other causes considered in the Fisher and Sublette summary include storms, fire, corrosion, and accidents.

3.4. Patterns Observed in Spill Data and Implications for Risk Mitigation

Several overarching conclusions arise from our analysis of state databases of spills and releases from oil and gas operations. First, although tanks are associated with fewer and smaller spills than pits, they are not infallible, and they tend to spill fluids that may be more harmful when released into the environment. The fact that both pits and tanks are subject to risk implies that policymakers should make sure that effective regulations exist for both wastewater storage options. Furthermore, regulations should acknowledge that pits and tanks are different in the types of risks that they convey, which can make pits more suitable than tanks for certain applications, and vice versa. For example, tanks may be preferable in regions with frequent, large precipitation events that could lead to overtopping of fluids that are held in a pit. On the other hand, tanks may be more suitable for storing toxic wastes, since even small leaks can be detected from a properly monitored tank.

Second, the relatively high frequency of spills due to overflows from pits and overfilling of tanks relative to spills from other causes suggests that regulators and members of the oil and gas industry should prioritize the reduction of risks from these causes. Fluid releases due to liner malfunctions are also commonplace, so strategies to reduce the occurrence of tears, holes, and improper installation of liners should be pursued.

Third, the state databases have allowed us to identify many incidents in which fluids were released into the environment and not recovered. Further research is required to identify whether these releases can lead to exposures that harm human and ecological health. This is especially true for pit overflows, leaks from tanks, and liner malfunctions, since we did not come across any studies in our literature review that estimated the risk of exposure to contaminants in shale gas and tight oil wastewater due to surface spills and leaching of pit contents into groundwater.

While examination of all three state databases has allowed us to start painting a picture of comparative risks from pits and tanks, the New Mexico OCD's database is informative thanks to its transparency and searchability. The flexible interface allowed us to tabulate reported spills by size, source, material spilled, and spill cause, which is the kind of information needed for stakeholders and the public to better understand the potential environmental impacts of on-site wastewater storage. Ideally, future versions of this database (as well as those maintained by other states) will provide data on the total number of pits and tanks in use. Such information is necessary for calculating the risks of a spill.

4. Mitigating Risks from On-site Storage of Wastewater: Existing Regulations

In this section, we describe the approaches states use to mitigate some of the risks from on-site storage of hydraulic fracturing wastewater. Data on regulations governing pits and tanks in the oil and gas sector are compiled for the 16 states that had any shale gas development in 2012 according to the US Energy Information Administration (EIA 2014) and three states that have the potential to produce shale gas. In addition, we treat New York's 2011 set of proposed regulations as if it has already been enacted.¹² The regulatory elements we describe below are those that appear most frequently in these existing and proposed state regulations. In general, we find more regulations associated with pits than with tanks; this may be because pits have a longer history in US oil and gas production.

State regulations for pits and tanks, and for oil and gas development more generally, are changing rapidly. As a result, our accounting of the number and stringency of regulatory elements for each state as described below will become increasingly outdated after publication of this paper. For example, at the time of writing, Pennsylvania is seeking to finalize a significant revision to Chapter 78 of its state code, which currently pertains to oil and gas wells and includes rules for temporary pits (used during drilling and hydraulic fracturing) and produced water pits. Specifically, updated Chapter 78 rules will only apply to conventional well drillers, and a new Chapter 78a is being prepared exclusively for unconventional drillers.¹³ Major revisions in these chapters include a ban on produced water pits for both conventional and unconventional operators. In addition, unconventional operators will not be allowed to store wastes in temporary pits; conventional operators will still be able to use temporary pits, although they will be required to obtain an individual permit if the pit is larger than 3,000 square feet or can store more than 125,000 gallons of fluid.

4.1. Pit Location

Regulations may address where pits can be located based on a variety of criteria. Some local governments specify zones in which pits can be constructed. For example, in Fort Worth,

¹² See High Volume Hydraulic Fracturing Proposed Regulations, New York State Department of Environmental Conservation, <http://www.dec.ny.gov/regulations/77353.html>, proposing modifications to 6 NYCRR Parts 52, 190, 550–56, 560, and 750.

¹³ For a near-final drafts of Chapters 78 and 78a, please refer to: [http://files.dep.state.pa.us/OilGas/BOGM/BOGMPortalFiles/TechnicalAdvisoryBoard/COGAC/2015/OCTOBER29/Final%20Annex%20A%20Chapters%2078%20and%2078a%20\(2015-10-27\).pdf](http://files.dep.state.pa.us/OilGas/BOGM/BOGMPortalFiles/TechnicalAdvisoryBoard/COGAC/2015/OCTOBER29/Final%20Annex%20A%20Chapters%2078%20and%2078a%20(2015-10-27).pdf)

Texas, pits associated with hydraulic fracturing activities may not be located in residential, commercial, business, or special use areas (Alpha Environmental Consultants 2009). In Utah, pits are not allowed in protection zones for drinking water (Utah Rule R649-9).

In addition, most states either restrict the use of or have additional construction requirements for pits located in environmentally sensitive areas. Depending on the state, such locations can include wetlands, floodplains, floodways, coastal areas, city easements, areas with high water tables, unstable areas (especially sinkholes), irrigated cropland, and areas near freshwater wells or springs. Sensitive areas can also be defined as those in which people are often present, such as residences, religious institutions, hospital buildings, and public parks. Most states either allow or do not allow pits in flood zones, but a few have regulations that seek to manage pits in flood zones through a performance standard or a permitting process.

Many states and localities restrict the use of pits in sensitive areas or define a minimum distance that pits must be set back from such areas. For example, in Pennsylvania, pits used for production fluids must be at least 100 feet away from a stream, wetland, or body of water unless a waiver is granted (025 Pa. Code § 78.57). Likewise, in New Mexico, temporary pits must be more than 300 feet from a permanent residence, school, hospital, church, or institution (New Mexico Title 19, Chapter 15, Part 17), while Colorado has recently passed new rules prohibiting pits within defined floodplains (Colorado 604.c.(2)B). Some states also regulate pits that are located close to sensitive areas by imposing additional construction requirements. For example, in locations in Arkansas where the water table is 10 feet or less below the ground surface, reserve pits must be constructed above ground or the operator must use a closed-loop system (Arkansas Rule B-17, Well Drilling Pits and Completion Pits Requirements). We find that states are very heterogeneous in the way they regulate setback restrictions. Utah is the most stringent, requiring that pits be constructed more than one mile from buildings. In contrast, Colorado requires that pits be only 1,000 feet away from high occupancy buildings, although pits within this “buffer zone” are allowed if they are reserve pits for drill surface casing, emergency pits, or pits used to hold fresh water (COGCC n.d.). Twelve of the states that we surveyed have no setback requirements in their regulations.

4.2. Pit Excavation

States currently regulate several aspects of pit excavation. Some states have requirements on either the areal size or volume capacity of pits. For example, in New Mexico, no temporary pit can have a volume greater than 10 acre-feet, while in Pennsylvania, produced water pits may not exceed 250,000 gallons in a single or connected network of pits (New Mexico Title 19,

Chapter 15, Part 17; 025 Pa. Code § 78.57). In addition, many states require that pit walls not exceed a certain slope. For example, Arkansas, New Mexico, and Pennsylvania¹⁴ do not allow pit walls that are steeper than a slope of 2:1 (Arkansas Rule B-17 (f)(2)(A); New Mexico Title 19, Chapter 15, Part 17; 025 Pa. Code § 78.57). Finally, many states require that pits be constructed at a certain height above groundwater tables to prevent seepage of waste into aquifers. In Pennsylvania, pits must be 20 inches above the seasonal high water table (025 Pa. Code § 78.62), while New Mexico requires a separation of 50 feet from groundwater (New Mexico Title 19, Chapter 15, Part 17). In places where groundwater is less than 20 feet below the surface, Wyoming requires use of a closed loop fluid handling system (Wyoming Chapter 4, Section 1 (u)).

4.3. Liners

Our literature review and analysis of state databases of spills indicate that liners were an important factor in determining whether pits are capable of preventing the release of contaminants in oil and gas wastewater. EPA (2001) estimates that approximately 12 percent of impoundments with liners experienced liner failure and that roughly 10 percent of all wastewater volumes are managed in impoundments that have had a liner failure. We are somewhat uncertain how these values reflect current shale gas and tight oil pit liner failure; though we expect that liner installations have improved since this EPA study, no current studies have examined the corrosivity of pit constituents and the rate at which they contribute to liner degradation.

4.3.1. Liner Material, Thickness, and Permeability

Regulation of liners has focused primarily on material, thickness, and permeability. Some states, such as Louisiana and Texas, allow for flexibility in the choice of liner material, including natural and bentonite clay as well as synthetic materials such as linear low-density polyethylene (LLDPE) and high-density polyethylene (HDPE) (URS Corporation 2011).¹⁵ Other states, such as Colorado and Pennsylvania, go further by specifically requiring synthetic liners (Colorado 904.b(1); 025 Pa. Code § 78.57). Figure 13 summarizes state-level regulations that require synthetic liner use for produced water pits in force as of May 1, 2014. Eight of the states that we surveyed require synthetic liners, while eight do not.

¹⁴ The 2:1 slope ratio requirement in Pennsylvania only applies to produced water pits.

¹⁵ See La. Rev. Stat. Ann. § XIX.307(A) (2014).

State regulations usually pair liner material specifications with requirements on liner thickness. Thicknesses of clay liners are usually specified in terms of mass of clay per unit area (e.g., pounds per square foot). Synthetic liners in Arkansas and Michigan must be at least 20 mil thick (one mil is equivalent to one-thousandth of an inch), while liners in Colorado and Pennsylvania¹⁶ must be at least 30 mil thick. Figure 14 summarizes state-level regulations on synthetic pit liner thickness in force as of May 1, 2014. Six states in our survey have no minimum liner thickness requirements, while ten states have thickness requirements that vary from 9 mil (Wyoming) to 60 mil (Utah).

Some states also specify requirements for liner permeability. Figure 15 summarizes state-level regulations on pit liner coefficients of hydraulic conductivity in force as of May 1, 2014. When provisions regarding liner permeability exist, they usually require liners with a coefficient of hydraulic conductivity of less than 1×10^{-7} centimeters per second. Synthetic liners are generally considered to have zero permeability, although leakage is still possible through ruptures and failed seams. Finally, some states may require that synthetic liners be paired with a foundation that is constructed according to given specifications or may require that pits have two liners. For example, in addition to requiring synthetic liners, Colorado requires a soil foundation having a minimum thickness of 24 inches after compaction and a maximum hydraulic conductivity of 1×10^{-7} centimeters per second (Colorado 904.d(2)). Utah requires two liners, with the additional provision that a leak detection system be installed in between the two liners.

4.3.2. Other Liner Features: Stitching, Seam joining, Anchoring, Slack, and Sub-bases

While most existing regulations on liners focus on the aforementioned characteristics, regulations have addressed other features of liners that may help mitigate risks. Regarding stitching and seam joining of liners, some states require specific lengths of overlap. For example, Arkansas and New Mexico require 4 inches of overlap, while Wyoming requires 2 inches (Arkansas Rule B-17, Well Drilling Pits and Completion Pits Requirements; New Mexico Title 19, Chapter 15, Part 17; Wyoming Chapter 4, Section 1 (w)(ii)). Several states also require that seams be oriented up and down slopes, not across, and also recommend factory-welded seams (New Mexico Title 19, Chapter 15, Part 17; URS Corporation 2011).

¹⁶ Pennsylvania specifies 30 mils for synthetic liners, but alternative thicknesses can be approved on a manufacturer-by-manufacturer basis if it is demonstrated that the alternative thickness performs as well as a standard 30 mil HDPE liner.

In order to increase the stability and effectiveness of the liner, some states have set requirements for an anchor trench around the perimeter of the pit. Depending on the size of the pit, engineers recommend the ideal size and distance from the pit the trench should be. The pit liner must extend to the depth of the trench in order for the trench to be backfilled to ensure that the liner stays in place. In Colorado, liners must be secured with a 12-inch-deep anchor trench, while in Fort Worth, Texas, and New Mexico, operators must anchor liners with an 18-inch-perimeter trench filled with compacted earth (Alpha Environmental Consultants 2009; New Mexico Title 19, Chapter 15, Part 17). In Michigan, the bottom of the lined pit must be weighted with earthen material or water before anchoring the ends of the liner on the surface or placing drilling muds in the pit (Michigan 324.407 (6)(c)).

Geomembrane liners expand and contract in different temperatures and require sufficient slack to prevent premature failure. Every liner material has a defined thermal expansion and contraction coefficients that allow operators to calculate the amount of slack needed. Operators must take these values into account when purchasing and installing pit liners. Furthermore, before lining a pit, some states require a smooth surface free of rocks and other debris that could lead to liner failure. Pennsylvania requires 6 inches of soil or gravel between liner and rock layers, while in Arkansas, a pit that uses a synthetic liner must have a sand or sandy material that is placed below the liner if a rocky or uneven surface is encountered (Arkansas Rule B-17 (f)(2)(B)(i); URS Corporation 2011).

4.3.3. Leak Detection Systems

Leak detection systems allow for identification of wastewater that may have been released from a pit due to holes or tears in liners. These systems are also potentially beneficial in that they may allow operators to avoid having to drain a pit in order to inspect liners. Many, but not all, leak detection systems are installed between the liners of a double-liner system. Some states, such as New Mexico and Utah, require leak detection systems in all pits (New Mexico Title 19, Chapter 15, Part 17; Utah R649-9-2.8.2). Some other states require detection systems only in certain cases. For example, Colorado requires leak detection systems only in environmentally and hydrologically sensitive areas (Colorado 904.e). Responses gathered from interviews with a liner company official and an oil and gas producer indicate that many shale gas operations do not install leak detection systems because of the temporary nature of wastewater storage in pits. Another significant concern is the excessive sensitivity of some detection systems.

4.4. Freeboard

Freeboard refers to the operational fluid level in a pit and is usually defined by the distance between the fluid level and the top of the pit. Freeboard requirements are some of the most common state regulations aimed at reducing the likelihood of spills and leaks from pits. Figure 16 summarizes state-level regulations on freeboard. Of the states surveyed, 12 have freeboard regulations requiring 1 to 3 feet of freeboard, with 2 feet being a common choice for many states. Notably, California, Michigan, and North Dakota did not appear to regulate freeboard as of March 1, 2014.

4.5. Fencing, Netting, and Screening

Fences are required by some state regulations in order to prevent unauthorized persons from entering a pit facility. Fencing is also intended to keep livestock and wildlife from entering the pit or drinking fluids contained in the pit. Some states, such as New Mexico, go so far as to specify the required height of the fence and the number of stands of barbed wire to be installed (New Mexico Title 19, Chapter 15, Part 17). Other states may require fencing only in specific cases, such as when pits are within a particular distance from a school or hospital or contain certain wastes. Some operators reduce or eliminate vegetation around the outside of the pit in order to discourage livestock and wildlife from drinking from or swimming in the pit.

The Migratory Bird Treaty Act (MBTA), 16 USC § 701-12 was first enacted in 1918 as part of the first generation of fish and wildlife laws (Lundquist et al. 2014). One section of the act makes it unlawful to “take” or “kill” a migratory bird, nest, or egg, except as permitted under regulations. In North Dakota in 2012, the government brought criminal charges against seven oil and gas producing companies for the unintended death of a few migratory birds in oil reserve pits. However, the district court dismissed the charges (Lundquist et al. 2014). The US Fish and Wildlife Service (FWS) currently interprets “kill” and “take” broadly, including unintended death in this definition, but no formal regulations from FWS currently exist (Lundquist et al. 2014). Several states have regulations recommending or requiring netting or screening of pits to prevent mortality of birds and other wildlife (Ramirez 2009). These nets and screens are suspended a few feet above the surface of the pit and prevent birds from landing. In North Dakota, all pits containing oil must be screened and netted, while in Montana, netting is required for pits that contain oil or produced water that has total dissolved solid concentrations exceeding 15,000 parts per million (ND 43-02-03-19.1; Montana 36.22.1227). Texas requires operators to screen, net, cover, or otherwise render harmless to birds (a) open-top storage tanks that are eight feet or greater in diameter and contain a continuous or frequent surface film or accumulation of

oil, (b) skimming pits, and (c) produced water pits (16 Texas Administrative Code §3.22). In 2012, BLM issued an instructional memorandum to its authorized officers to assure that pits, tanks, and similar structures are netted or screened with the goal of preventing the death of birds protected under the MBTA (BLM 2012). Netting has the added benefit of reducing any debris that may enter the pit and cause a breach in the liner (Carroll 2011). However, all of these barriers will increase pit construction costs and potentially slow down operations.

4.6. Spill Reporting

Generally, accidents at oil and gas wells, including wastewater spills from associated pits and tanks, must be reported to state governing bodies within 24 hours of the accident occurring. However, there is heterogeneity across states in terms of accident reporting requirements, as illustrated in Figure 17. While we find that some states, Montana, Colorado, Virginia, and Alabama, require that spills be reported immediately, we find no evidence of regulation requiring spill reporting in California. Texas requires operators to immediately notify the Railroad Commission in the event of a leak or spill, and such notice must be followed up by a letter describing the event, including “the volume of crude oil, gas, geothermal resources, other well liquids, or associated products lost” (16 Texas Administrative Code §3.20). In many cases, only certain kinds of spills require reporting. In Utah, for example, spills need to be reported if they constitute a “major event,” which is defined as a discharge of more than 100 barrels of liquid that is not fully contained on location by a wall, berm, or dike (Utah Rule R649-3-32). Pennsylvania requires spills of 5 gallons or more of any substance to be reported within 2 hours of detection (Pa. Code § 78.66).

4.7. Closure and Reclamation

States have different rules related to pit closure and remediation requirements. Some states allow for passive closure, allowing fluids to evaporate and ultimately be disposed of in place, pumping water-based drilling fluids back down the bore of the well, or solidifying or stabilizing the fluid by combining it with available native soils and burying it in situ. Passive closure is a low-cost means of disposal but is not common in most current oil and gas operations.

A commonly used regulation is a limit on the amount of time allowed until pit remediation must occur. States have different requirements on the length of time fluids can remain in pits and the length of time between fluid removal and remediation. For states that specify a maximum length of time to closure, this can be as short as 30 days (Alabama and North Dakota) or as long as a year (Kansas, Utah, and Wyoming). Furthermore, these regulations can

be more detailed in the degree to which remediation and closure are achieved. In Pennsylvania, unless pits are holding material for disposal, they must be removed or filled within nine months after well drilling is completed (025 Pa. Code § 78.56). In Arkansas, the pit and applicable portion of the drill pad not used for production purposes must be returned to grade, reclaimed, and seeded within 180 days after the drilling or workover rig is removed from the site (Arkansas Rule B-17 (h)(6)). In North Dakota, contents of the pit must be removed within 72 hours after operations have ceased, and the pit should be reclaimed within 30 days of operations ceasing (ND 43-02-03-19.3). Some states also define a necessary canopy cover required after pit closure.

With hydraulic fracturing technology permitting multiple natural gas wells at a site, pits intended for temporary storage may be reused, potentially increasing the life of the pit and delaying the date on which a pit is closed and remediated. Moreover, according to standard practice, when market prices for natural gas are low, operators may choose to remain at a site but hold off on drilling additional wells. We are unaware of specific regulations or industry practices that allow for protection of pits during temporary closures of well sites.

4.8. Tanks

States generally have fewer regulations governing tanks than for pits. In Arkansas, closed-loop systems are required within 100 feet of water bodies (Arkansas Rule B-17, Well Drilling Pits and Completion Pits Requirements). Michigan requires that tanks be used for produced water, completion fluids, and other liquid wastes, while drilling mud and drilling fluids may be contained in pits except in areas zoned residential (Michigan 324.407 (3), 324.502, 324.702, 324.1005). Ohio, Arkansas, and Michigan all have setback regulations for tank batteries from water supply and buildings (Richardson et al. 2013). New York's proposed regulations require the use of water-tight tanks for flowback, whereas other wastes can be stored in pits. Colorado requires mitigation measures for tanks located within the 1,000-foot "buffer zone" setback from high occupancy buildings, including liners beneath and berms around certain crude oil, condensate and produced water tanks (COGCC n.d.). Because tanks are more likely than pits to fail in a more catastrophic way, releasing all of their contents, 22 states require that tanks be surrounded by a secondary containment structure to hold the capacity of the tank (GWPC 2014). As of 2013, 14 states required routine maintenance, and 4 states required that tank battery sites be remediated or the materials disposed of in accordance with specific requirements (GWPC 2014).

Storage tanks used in natural gas production are subject to EPA's 2012 New Source Performance Standards (NSPS) for VOCs if they were constructed, modified, or reconstructed

after August 23, 2011, and have the potential to emit 6 or more tons of VOCs a year. In the Final Rule, issued on April 17, 2012, tanks subject to the NSPS were required to reduce VOC emissions by 95 percent by October 15, 2013. EPA expected this reduction to be accomplished by routing tank emissions to a combustion device (EPA 2012). These performance standards were updated in March 2013 to ensure that tanks with the highest emissions are controlled first, while providing tank owners and operators time to purchase and install VOC controls (EPA 2013).

4.9. Addressing Pit and Tank Specifications in Permits

While many elements are addressed in state codes as uniform command-and-control regulations, some states choose to address regulatory elements using permit documents. Establishing general rules for all pits in a given state simplifies the governing of oil and gas operations in general, but some risks cannot be addressed sufficiently with uniform regulations due to economic, geologic, or operator differences within states. Addressing requirements for pit specifications within the permitting process allows for flexibility in addressing these issues.

Eleven states in our study require operators to apply for a permit before construction of a pit can take place. While some states (e.g., Pennsylvania) include the pit permit within a broader permit-to-drill application, New Mexico requires a separate permit for pits and closed-loop systems. Permit applications for pits and tanks may require information such as the exact location where the wastewater storage will take place, the size of the structure, the type of fluids stored in the structure, liner characteristics, and setback distances from water bodies and buildings. For example, Wyoming requires freeboard capacity to be reported in permit applications (Wyoming Chapter 4, Section 1 (r)(i)); freeboard requirements are typically set at 2 feet in a permit but this is reviewed on a case-by-case basis. Likewise, the only pits allowed in Michigan are drilling pits and freshwater storage pits, which are in close proximity to the well surface location, and users must submit permit applications that identify floodplains associated with surface waters within 1,320 feet of the proposed well (Michigan 324.201). Texas requires individual permits for produced water pits, and during review of the applications, staff consider the location, depth to groundwater, distance from surface water, type of waste fluid to be contained, liner installation, leak detection procedures, and duration of pit operations when determining the requirements for siting, construction, operation, and closure. In Figure 18, we provide New Mexico's pit permit application document as an example of what these applications look like.

4.10. Pits vs. Tanks

The American Petroleum Institute (API) and the Independent Petroleum Association of America (IPAA) do not exhibit a clear preference for the use of either pits or tanks for on-site wastewater storage. Best practices specified by API do not distinguish among different fluid types and storage facilities, ultimately allowing all fluids to be stored in open pits or tanks (Richardson et al. 2013). In an informal industry survey, some IPAA members expressed the view that tanks and pits each have their advantages in specific circumstances. Many factors must be considered before operators decide whether to use pits or tanks, including regulatory requirements, lease agreements, drilling fluid type, location size, availability of equipment, proximity to disposal facilities, proximity to environmentally sensitive areas, depth to groundwater, cost, and public opinion.

According to the IPAA members, each type of management system has costs and benefits. For example, tanks can be more protective in areas with shallow groundwater tables because leaks are more easily observable from tanks than from pits. On the other hand, if the groundwater table is deep and surface area is limited, pits could be preferred over tanks. A pit could be excavated to a greater depth, holding more fluids per square foot than tanks can. IPAA members also warn that steel tanks are more prone to static electricity and lightning strikes, which can result in tank fires, and the use of tanks increases truck traffic, potentially leading to a greater number of traffic accidents. Tank systems commonly involve piping and valves that can fail or be left open due to human error, resulting in spills, but pits can become targets for dumping of waste unrelated to oil and gas activity by the general public. In addition, incidents do occur where portable lined storage tanks fail because of poor foundation stability, metal or liner fatigue, or improper installation. On the other hand, it is more difficult to control air emissions from fluids containing hydrocarbons that are stored in pits, and pits have the potential to represent a safety hazard to wildlife (including migratory birds) and livestock, as these animals may be unable to escape after entering the pit. Like pits, tank systems can also break down, causing environmental risk, if not properly monitored and maintained.

Some state regulators have indicated that pits exhibit more maintenance challenges when compared to tanks, especially with regard to the management of pit berms, which are subject to general stormwater and erosion issues. In addition, pit berms deteriorate and the practice of cleaning out pits and adding pit bottoms to the berms results in migration of this material onto adjacent land. Pits can also be more problematic from a closure and reclamation perspective. When releases occur from lined pits without leak detection, the impacts are sometimes not

discovered for years. Furthermore, it may be challenging for the regulatory agency to properly clean up historic releases if the pits were associated with multiple operators over time.

BLM is perhaps the most stringent regulator of pits, basically not allowing their use. In 2015, BLM released final standards for hydraulic fracturing on public and tribal lands, which include a new requirement that all produced water be stored in “rigid, enclosed, covered, or netted and screened above-ground tanks, subject to very limited exceptions in which lined pits could be used” that may not exceed a 500-barrel capacity (BLM 2015). BLM’s justification for this new requirement is based on the argument that tanks are less prone to leaking than pits, are safer for wildlife, and will have fewer air emissions. In addition, BLM cited several benefits that tanks afford to oil and gas operators, including quicker site preparation, increases in safety, and fewer monitoring and mitigation requirements.

4.11. Comparison of Existing State Regulations

In reviewing the different approaches that can mitigate the risks from on-site storage of shale gas and tight oil wastewater, we encountered significant heterogeneity across states in the number of these approaches that are regulated and the stringency of these regulations. In order to gain a general overview of this heterogeneity, we follow the approach of a recent RFF study titled *The State of State Shale Gas Regulation*, which catalogues a broader set of 25 state regulations relevant to shale gas, including elements associated with site selection and preparation, well drilling, hydraulic fracturing, excess gas disposal, and plugging and abandonment (Richardson et al. 2013). We borrow information on two of the surveyed regulatory elements that apply to wastewater storage—freeboard requirements and minimum pit liner requirements—and survey an additional 22 regulatory elements, all of which apply to pits or tanks, for 19 states. This gives us a total of 24 regulatory elements, which are as follows:

Permitting

1. Permit requirements

Siting

2. Flood zone requirements
3. Setbacks from buildings
4. Setbacks from water bodies

Construction

5. Maximum volume
6. Maximum depth

7. Freeboard requirements
8. Leak detection system requirements
9. Levee or berm requirements

Liners

10. Liners for all pits
11. Minimum thickness
12. Maximum permeability

Access-limiting features

13. Fencing requirements
14. Screening/netting requirements
15. Signage requirements

Operation

16. Ongoing inspection/monitoring requirements
17. Record-keeping requirements
18. Spill/accident reporting time requirements

Closure and reclamation

19. Maximum days to closure after completion
20. Maximum days to remediation after closure
21. Closure permitting requirements
22. Closure notification requirements
23. Remediation requirements
24. Post-closure testing requirements

Because states generally have fewer regulations governing tanks than for pits, these 24 regulatory elements relate primarily to pits and not tanks.

As with *The State of State Shale Gas Regulation* report, several caveats are in order regarding the following analysis. First, although the regulatory data in our analysis do allow us to make high-level comparisons among states, they do not fully explain regulatory heterogeneity, nor do they allow us to judge the relative quality of any pit or tank regulations that exist in different states. To do so would require data on enforcement, environmental outcomes, and regulatory costs, none of which are systematically assessed in this report. Second, our survey

does not include federal, local, or, for the most part, state-level regulation that does not apply state-wide. Third, the case-by-case nature of regulation by permitting makes it difficult to evaluate stringency for some regulatory elements; for these elements, we are able to indicate only whether a state regulates a given area via permit. Finally, although we have made every effort to find any and all state regulations relevant to each pit or tank element in our study, errors of either interpretation or omission are possible. In particular, we were unable to find evidence of regulation for some states and elements. Acknowledging the small but real chance that regulations do exist but that we failed to find them, we interpret such cases as “no evidence of regulation found” rather than “no regulation.”

4.11.1. How Many Elements Does Each State Regulate?

For each of these 24 pit elements, we first recorded whether we found any relevant regulation in each of the 19 states in our survey, regardless of its form or stringency. None of the states we surveyed regulate all 24 elements, but New Mexico and Oklahoma are tied for the largest number of regulated elements, at 20. All states regulate at least 6 of the elements in our analysis, with California and Virginia regulating the fewest. Between these extremes, we found relatively smooth variation among states (see Figure 19). While this variation illustrates differences among state regulatory approaches and is a representation of how broadly each state regulates across the elements in our analysis, it is at best an extremely rough measure of the overall extent of any state’s shale gas and tight oil regulation in this area. One certainly should not assume that states that regulate more pit and tank elements regulate on-site wastewater storage more tightly or more effectively.

4.11.2. How Stringently Does Each State Regulate?

For many of the pit and tank elements in our analysis, our data allow us to say only whether a state regulates an element, but it is often impossible to determine how stringent state regulations are. However, for some elements, many states use quantitative regulations; for example, freeboard requirements are often expressed in terms of number of feet, while spill reporting requirements usually specify a reporting time in hours. For this comparison, we focus on the following nine elements, which are regulated quantitatively by at least some states:

Siting

1. Setbacks from buildings
2. Setbacks from water bodies

Construction

3. Maximum volume

4. Freeboard requirements

Liners

6. Minimum thickness
7. Maximum permeability

Operation

8. Spill/accident reporting time requirements

Closure and reclamation

9. Maximum days to closure after completion
10. Maximum days to remediation after closure

In order to measure stringency across these regulations for each state, we normalize the stringency of each regulation to the same scale.¹⁷ We accomplish this by defining a regulatory range between the most and least stringent state rule for each element, placing each state on that range, and then normalizing the range to a 0–100 percent scale. This allows stringency to be compared not only among states, but also across otherwise dissimilar regulatory elements.

Figure 20 provides a ranking of states by the average of the normalized stringencies of their regulations for elements they regulate in a quantifiable way. California regulates most stringently across these elements, with an average stringency of 100 percent, while Wyoming regulates them least stringently, with an average stringency of 20 percent. However, California regulates only one element quantitatively, while Wyoming regulates five elements quantitatively. Among the top five shale gas producing states (by gas wells in 2011), Ohio is the most stringent across these elements (with an average stringency of 96 percent), followed by Texas (75 percent), Pennsylvania (71 percent), West Virginia (51 percent), and Oklahoma (41 percent).

Because the stringencies reported in Figure 20 consider only those elements that each state has regulated quantitatively, it ignores cases where a state has no regulation at all for a quantifiable element. It is arguably accurate to treat these cases as minimally stringent rather than ignore them, as they are in the above ranking of states. By assigning a zero stringency value

¹⁷ For example, the most stringent states regarding freeboard requirements are Montana and Oklahoma, with a freeboard of 3 feet, while eight states are tied for the least stringent freeboard requirement, with a freeboard of 1 foot. In this case, Montana and Oklahoma would be assigned a normalized stringency of 100 percent and the eight states tied for least stringent setback would be assigned a normalized stringency of 0 percent. The remaining nine states have a freeboard requirement of 2 feet, so their normalized stringencies would equal 50 percent.

for each element for which we were unable to find evidence of any regulation, we can rerank the states using an “adjusted” normalized stringency. Figure 21 illustrates how, under this adjusted measure, New York’s proposed regulations appear most stringent, at 71 percent, while Wyoming is least stringent, at 11 percent. Among the top five states by number of wells (as of 2011), Pennsylvania is most stringent, while Ohio now appears as the second least stringent across these elements.

Several caveats are in order regarding the rankings illustrated in Figures 20 and 21. First, while many states use command-and-control approaches that set a uniform statewide minimum standard, operators are often allowed to apply for exceptions. In these cases, the stringency of the underlying command-and-control rule does not fully convey the effective stringency of the state’s regulatory regime. Second, this stringency analysis makes no effort to measure the relative importance of different regulatory elements. For example, our analysis would not account for the fact that regulations on pit liner thickness may have a greater impact on environmental outcomes or compliance costs than regulations on spill reporting time. Third, differing conditions across states may justify regulating more or less stringently or perhaps not regulating an element at all. Fourth, just because a state regulates an element more stringently does not necessarily mean that the regulation is more effective. For example, states that require 3 feet of freeboard are assigned a normalized stringency of 100 percent while states that require 2 feet of freeboard are assigned a normalized stringency of 50 percent, but it is possible that pits can function effectively with only 2 feet of freeboard. Finally, because we are limited to elements for which we were able to find quantitative regulations, Figures 20 and 21 cannot be used to evaluate the general stringency of each state’s regulations regarding pits and tanks, and states are not “penalized” for choosing nonquantifiable regulatory tools.

4.12. The Role of Liability, Insurance, and Bonding

As described earlier in Section 4, oil and gas producers often adopt measures to reduce the risks associated with pits and tanks in response to direct regulation from the states. Many economists would attribute the lack of risk mitigation in the absence of these regulations to the incentives faced by the oil and gas operators. Firms do not have an incentive to implement risk-mitigating measures that are costly in terms of money and time if they yield mostly external benefits (e.g., benefits to human and ecological health) and few private benefits. Because firms cannot internalize these external benefits, they may not undertake sufficient risk mitigation.

However, the literature on law and economics suggests that a well-functioning tort system could provide the necessary incentives for operators to reduce the risk of their activities

to a socially optimal level. The US tort system allows anyone who has suffered a loss from the actions of an oil or gas operator to present a claim for compensation in court. Economists have shown that in the presence of perfect information, a tort system that works perfectly will lead to firms taking on optimal levels of precaution (Brown 1973). This is because firms face the risks of paying for the costs of the damages they cause, and as a result, they will make choices that will reduce the risks of damages, thus aligning their actions to what minimizes total expected social costs.

But tort systems rarely work perfectly. Because of administrative or legal costs, firms may not be sued for harms they cause, and it is often difficult to attribute damages to a particular firm. Furthermore, the tort system may not yield the socially optimal levels of risk avoidance. Damages that are discovered after the firm that has caused them ceases to exist will not be paid for, and US bankruptcy law limits payments for damages to the total value of the firm, which the actual damages may exceed. These issues may be magnified in the shale gas and tight oil industry, which has only a few large producers but many smaller producers that are less likely to be able to finance the cost of damages that they may produce (Davis 2015). Rubin (2012) also cites the challenges posed by difficulties in applying negligence because of challenges associated with defining due care and determining whether exercising such care will prevent harm, and difficulties in applying private nuisance law because proof of intent may be difficult to establish. All of these issues are likely to apply to damages that are caused when oil and gas producers take on excessive risk in managing their on-site storage of wastewater in pits and tanks.

An oil and gas producer's financial liability for damages can be fulfilled by insurance companies. One possible strategy for regulators is to make insurance for pits and tanks mandatory, thus insuring that funds are available for cleanups. However, anecdotal evidence suggests that some insurers find it difficult to price the risks associated with shale gas production because of their uncertain nature, and this uncertainty is likely to carry over to pits and tanks. In addition, insurers may be just as likely to try to find ways to avoid paying for damages as the oil and gas producers they are insuring. Finally, assuming that insurance does effectively cover potential damages, there still remains the problem of oil and gas operators being involved in what is called a moral hazard problem because the insurance insulates them from the consequences of their actions.¹⁸

¹⁸ It should be noted that the moral hazard problem is associated with insurance schemes in general and is not unique to insurance that is taken up by the oil and gas industry.

Another policy tool is bonding requirements, which require producers to post bonds that can be used to pay for claims made against the company. In its existing format, the oil or gas operator deposits cash or another liquid asset into a holding account, and the bond is returned after well production has finished and the producer has complied with all regulatory requirements. Davis (2015) provides a description of current bonding requirements for natural gas drilling on federal lands under the Mineral Leasing Act of 1920. Davis (2015) also summarizes state-level bonding requirements, which apply on nonfederal lands, and points out the significant differences across states in minimum dollar amounts for bonds for individual leases. Given the significant risks associated with on-site wastewater storage compared with other components of the shale gas and tight oil production processes, concerned state regulators may consider implementing bonding requirements that apply specifically to the construction, use, and closure of pits and tanks.

5. Mitigating Risks from On-site Storage of Wastewater: Costs and Benefits

Our literature search yielded very little information on the costs and benefits associated with options that oil and gas producers have to mitigate the risks from on-site storage of shale gas and tight oil wastewater in pits and tanks. Generally, more data are available on the costs side than on the benefits side. As mentioned in Section 2, there is a lack of studies that quantify the risks to human and ecological health of shale gas and tight oil wastewater storage in pits and tanks, and as a result, quantifying the benefits of reducing these risks is impossible. This, in turn, makes it impossible to compare the costs of the mitigation options with their benefits. In this section, we summarize the small number of available cost and benefit estimates in the literature. We also identify the cost and benefit estimates that would be necessary for a rigorous cost–benefit analysis but are currently not available, and we describe methods that future studies can employ in order to estimate these key costs and benefits.

5.1. Costs and Benefits of Preventing Spills and Releases from Pits and Tanks

The specifications for pits and tanks required by the regulations discussed in Section 4 will impose additional capital and operational costs if oil and gas producers would not have pursued these specifications in the absence of regulation. Regarding pit location, zoning rules can impact property values or force operators to construct pits farther away from drilling activity, potentially increasing water transportation and land costs. Setback requirements for sensitive areas are put in place to protect both human and ecological health, but they can potentially reduce efficiency in pit placement, increasing fluid management costs. However, these setback-

type rules may be more cost-effective for oil and gas operators than zoning rules that prohibit all pit construction within large areas.

Regarding pit excavation, limitations on the maximum size of a pit are intended to minimize land impacts but can also reduce the utility of a pit as a water management solution if they are not consistent with the volume of wastewater that the oil and gas producer intends to store. Requirements for pit wall slope are put in place to prevent soil erosion, decrease waves, increase worker safety during construction, and prevent the dislodging of liners. However, flatter pit walls will decrease the volumetric capacity of a pit, making it more costly to store an equivalent volume of wastewater. If pits are required to be constructed at a certain height above groundwater tables, depending on the geology of a specific area, the requirement could eliminate pits as a viable fluid storage option.

Our analysis of state spill databases reveals that liner malfunctions are one of the most common causes of accidental release of pit contents into the environment. Several studies indicate that composite liner systems involving multiple barrier components can reduce the risk of wastewater leakage from pits. One somewhat dated study of 28 double-lined landfill facilities and 8 double-lined surface impoundment facilities finds that these facilities typically meet EPA recommended action leakage rates (Bonaparte and Gross 1993). A study based on 20 years of observations by the National Research Council (NRC 2007) determined that composite liners composed of geomembranes and either compacted clay or geosynthetic clay layers provide better protection than any single component acting alone.

The liner installation process may be just as important as the characteristics of the liner itself, if not more important, in determining the effectiveness of a pit. The NRC study finds that geomembranes installed following strict quality assurance protocols perform better than those installed without such requirements. Installation crews must ensure that liner materials are not defective, seams are properly joined, and liners are not physically damaged during construction, especially for materials that tear or crack easily. State regulators have also indicated that it is important to ensure that pit foundations are free of rocks, jagged edges, or debris that could puncture a liner after installation. According to industry experts, some liner materials are also sensitive to high temperatures, so crews must be aware of how long these liners are exposed to sunlight.

Requirements for pit liners are likely to incur additional costs to oil and gas producers. Based on a survey of five oil and gas companies, the Texas Railroad Commission provides cost estimates for 12-mil nonreinforced and 12-mil reinforced plastic liners to be employed in reserve and workover pits.¹⁹ These estimates are summarized in Table 5. For a reserve pit that measures 100 feet by 150 feet by 8 feet, the commission estimates that the lining cost for a 12-mil liner will be \$2,721 per pit. For a workover pit that is 10 feet by 20 feet by 6 feet, it estimates that a 12-mil liner would cost \$500 if a contractor installs it and \$75 if installed by the operator. However, the estimates in Table 5 show that there may be significant variation in liner costs across different pit users.

A more recent EPA study employs an estimate of \$0.34 per square foot (\$0.39 per square foot in 2014\$) for clay liners and \$0.69 per square foot (\$0.79 in 2014\$) for 40-mil geomembrane liners (Maxey 2007). For the same pit measuring 100 feet by 150 feet by 8 feet, these per-square-foot costs would translate to per-pit costs of \$7,410 and \$15,010 (in 2014\$), respectively.²⁰ A study of landfill liners in Illinois provides estimates for more complicated liner setups (Munie 2003). This study estimates that a 5-foot recompacted soil liner costs \$2.06 per square foot to install (\$2.67 in 2014\$), while a single composite liner consisting of a 3-foot clay liner and a 60-mil HDPE liner would cost \$1.73 per square foot (\$2.24 in 2014\$). These costs translate to per-pit costs of \$50,730 and \$42,560 (in 2014\$), respectively.

More stringent stitching and seam joining requirements are likely to increase costs to operators, as additional liner material must be purchased and qualified individuals must be hired from the liner manufacturer. Hydraulic conductivity requirements are closer to a performance standard than liner thickness and material requirements, thus allowing operators more flexibility in how to achieve this goal with the lowest-cost option available.

Cost estimates for leak detection systems are difficult to obtain. One available estimate is associated with landfills in Illinois, for which a double composite liner employing 60-mil HDPE liners and a leak detection system is estimated to cost \$3.29 per square foot (\$4.26 in 2014\$) (Munie 2003). At \$80,940 (in 2014\$) for a pit measuring 100 feet by 150 feet by 8 feet, these costs are significantly more than the liner-only cost estimates above. The 2015 BLM final rule

¹⁹ Response to comments on proposed rule in Texas Administrative Code, Title 16, Chapter 4, Subchapter B. Oil and Gas Division, Railroad Commission of Texas (September 20, 2002).

²⁰ These per-pit cost estimates assume that both the bottom and sides of the pit are lined with the material in question.

for hydraulic fracturing on public and tribal lands cites a leak detection system cost of \$6,100 for a half-acre pit and \$6,250 for an acre pit, which is equivalent to a per-operation cost of \$1,200 and \$1,300, respectively, assuming that a pit services five completions (BLM 2015).

Some studies have shown that tanks and closed-loop systems may decrease wastewater storage costs relative to pits. The New Mexico Oil Conservation Division document on pollution prevention best management practices (NMOCD 2000) cites a case study conducted by the Langham Petroleum Exploration Corporation, which found that replacing a conventional reserve pit (235 feet by 77 feet by 5 feet) with a closed-loop drilling fluid system would lead to cost savings of \$11,000. According to the study, the primary sources of these savings lie in reduced costs associated with drill site installation, fluid hauling and disposal, dirt work, and surface damage payments. A different study by Longwell and Hertzler (1997) in Colorado estimates that moving from reserve pits to closed-loop drilling would reduce fluid handling costs from \$17,020 to \$15,600. These savings come from reduced land requirements, surface damages, berm building costs, and mud and water hauling. On the other hand, the need to procure a dewatering unit for a closed-loop system can lead to increase costs. Furthermore, according to industry experts, setting up a closed-loop system may be difficult and costly in remote oil and gas operations.

In a 2010 petition to EPA, Amy Mall and Diane Donnelly from NRDC describe a study of two wells that were being drilled 200 feet apart “through the same formations, using the same rig crew, mud company and bit program” in Matagorda County, Texas. One well used a closed-loop system, while the other used traditional solids-control equipment. The closed-loop system resulted in a 43 percent savings in drilling fluid costs, 23 percent fewer rotating hours, fewer days to drill the wells to comparable depths, a 37 percent reduction in bits used, and up to 39 percent improvement in penetration rates (Mall and Donnelly 2010). Further cost savings may be feasible in the future as new technologies such as clear water drilling fluid (CWDF) and drilled solids stripping units (DSSU) are developed (Redmon et al. 2012). In Colorado, closed-loop systems are required within 1,000-foot “buffer zone” setbacks from high occupancy buildings (Colorado 604.c(2)B).

The 2015 BLM final rule provides several estimates for the cost of storing flowback and produced water in pits and tanks. Two of these estimates are based on solicited comments. The first commenter claimed that lined impoundments are more cost-effective than steel tanks; expressed as five-year net present costs, a pit would cost \$2.3 million to build, while renting enough tanks to hold an equivalent volume of wastewater would cost \$23 million. This commenter assumed that it would take 500 tanks to replace one pit, each incurring a daily rental

fee. The second commenter suggested open-pit costs of \$447,000 and closed-loop system costs of \$267,000, though the associated timeframe is unclear. BLM also contacted service providers in order to estimate baseline costs of constructing and operating tanks and pits. According to these estimates, tanks are less costly than pits on smaller- and medium-volume jobs but likely to be more costly than pits for higher-volume jobs.

While these studies indicate that closed-loop handling systems may reduce the risks of oil and gas wastewater storage to human and ecological health, our analysis of state databases on spills reveals that tanks are an important source of reported releases. This suggests that the replacement of pits with closed-loop systems may not yield significant benefits unless the risks from tank spills are concurrently addressed.

5.2. Potential Benefits to Human Health

EPA (2001) estimates that more than 20 million people live within 2 kilometers of an industrial impoundment that was in operation during the 1990s, and about 10 percent of these impoundments have a domestic drinking water well located within 150 meters of the impoundment's edge. Further, it is estimated that approximately 870 impoundments that manage VOCs had at least one residence within a 150-meter radius. These figures, which characterize the proximity of humans and human activity to surface impoundments, may aid in the assessment of human exposure to air-, groundwater-, and surface-water-borne contamination. This characterization, in turn, may serve as one measure of the benefits of additional siting regulations for pits. However, these figures represent impoundments at industrial facilities in general and are not specific to hydraulic fracturing operations. As a result, a detailed study of shale gas and tight oil wastewater pits via a survey directed toward the oil and gas industry would be required for a more accurate risk assessment.

The economics literature on the benefits of protecting water quality has focused primarily on drinking water (Adamowicz et al. 2011), and studies in this literature have generally shown that the economic net benefits of safe drinking water (measured as willingness to pay) are very large. While the degree to which drinking water is contaminated by oil and gas development is an ongoing debate, there is evidence that the perception of risks to drinking water supplies may be widespread. A recent hedonic property study in Pennsylvania suggests that perceived groundwater risk related to nearby gas wells reduces property values by up to 24 percent (Muehlenbachs et al. 2015) in comparison with identical homes farther away on a public water supply. Perceived risks to water quality may also lead to losses to agriculture as a result of consumer resistance to food grown near oil and gas operations (Pennsylvania State University

2010). Zabel and Guignet (2012) conducted a hedonic analysis to estimate the effect on property values of leaks and cleanup activities at nearby leaking underground petroleum storage tanks (LUSTs). The authors find that while typical LUST sites do not significantly affect property values, more publicized and severe sites can decrease surrounding home values by more than 10 percent. In this study, pollution severity was represented using BTEX concentrations in potable wells and monitoring wells at the LUST facility and the surrounding area.

To estimate the actual (as opposed to perceived) social costs of drinking water impacts, the impacts themselves would first need to be carefully quantified. Then, to monetize these impacts, economists can employ a variety of methods to obtain estimates of the willingness to pay to reduce any potential damages. A recent study (Bernstein et al. 2012) used contingent valuation methods to estimate the value residents of the Susquehanna Valley place on additional safety measures that would protect the local watershed from contamination by the shale gas industry. Results show that households are willing to pay an average of \$10.46 per month for those additional safety measures. In a survey of 1,600 adults in Pennsylvania and Texas, Siikamäki and Krupnick (2013) asked respondents to choose among several potential government programs for reducing risks of shale gas development to groundwater, surface water, and air pollution, with each program being associated with a cost. On average, households were willing to pay around \$20 to \$30 per year to eliminate risks to 1,000 drinking water wells, although households in Texas exhibited a greater willingness to pay than Pennsylvanians. Texans were also willing to pay more for reducing risks to surface water. These estimates for risks associated with shale gas production are in line with previous empirical studies on the value that people place on the availability of clean water (Carson and Mitchell 1993; Egan et al. 2008; Leggett and Bockstael 2000).

The economics literature has estimated the benefits of reducing air pollutant emissions in a variety of other contexts. Groosman et al. (2011) find that annual benefits from reductions in VOC emissions from the transportation sector as a result of the climate policy contained in the Warner-Lieberman bill (S. 2191) would have equaled \$17.3 billion. Currie et al. (2015) examine the impact of toxic emissions from industrial plants on housing markets and infant health. The authors find that plant openings lead to 11 percent declines in housing values within 0.5 miles, or a loss of about \$4.25 million, and that a plant's operation is associated with a roughly 3 percent increase in the probability of low birth weight within 1 mile. In a study comparing air quality measurements and infant health data in areas of the Dallas–Fort Worth region that are inside and outside the Barnett Shale, Hill (2014) finds that living in a zip code within the shale gas region reduces birth weight and gestation length on average, with mixed effects for low birth weight and

premature birth. Because these estimates of the benefits of reducing air emissions were obtained from vastly different settings, estimating the value to human health of reducing air emissions from pits and tanks would require its own study.

5.3. Potential Benefits to Ecological Health

In its survey of industrial impoundments, EPA (2001) finds that about 20 percent of the impoundments in its sample were located within 150 meters of a fishable water body. Johnson et al. (2003) provide results indicating that up to 76 percent of impoundments in the United States could not be ruled out as having the potential for adverse ecological impact. Ramirez (2009) concludes that netting appears to be the most effective method of keeping birds from entering waste pits, although nets must be properly installed to prevent sagging; heavy snow loads may cause the net to sag into a pit, exposing its contents to waterfowl. This study also finds that flagging is an ineffective deterrent for preventing wildlife mortality in pits.

In their summary of fluid releases in Oklahoma, Fisher and Sublette (n.d.) state that the most frequently reported impact of oil releases between 1993 and 2003 (see Table 6) was injury to surface water (defined as oil reaching a stream, lake, or pond), followed by crop or stock injury (defined as death or injury of livestock or damage to a crop or pasture), soil injury, erosion, groundwater injury (defined as cases in which groundwater contamination was reported), and wildlife injury (defined as injury or death of fish or wildlife). The impacts of saltwater releases exhibited the same ranking as for oil releases. Implementing additional risk mitigation measures as described in Section 4 may reduce the frequency of these ecological damages and thus lead to an increase in societal benefits. However, it should be noted that these figures include impacts caused by releases other than from pits and tanks.

There is some concern that contamination of water resulting from unconventional fossil fuel production may lead to losses in the agricultural sector, particularly for livestock producers. A study based on interviews with animal owners near gas drilling operations in Colorado, Louisiana, New York, Ohio, Pennsylvania, and Texas identifies potential links of animal health problems to contaminated water, including exposure to hydraulic fracturing fluid and wastewater (Bamberger and Oswald 2012). The study also identifies reproductive, neurological, and other health issues in companion animals, which may convey significant losses to their owners. In 2010, the Pennsylvania Department of Agriculture quarantined cattle from a Tioga County farm after a number of cows came into contact with a holding pond that collected flowback water from a nearby hydraulic fracturing site (PADEP 2010). As a result, government regulations or voluntary industry practices on wastewater pits that reduce the frequency of these incidents will

lead to benefits to the agricultural sector in the form of reduced livestock deaths and health damages that may make livestock unsuitable for sale.

Water quality degradation may also generate significant economic damages through impacts on recreation and other water uses. Economists have demonstrated that these uses have significant value. General estimates of the annual benefits generated by the US Clean Water Act, most of them related to recreation, are in the range of \$22 billion to \$29 billion, in 1990\$ (Carson and Mitchell 1993; Freeman 1982). There are also many estimates of the value of water quality improvements on a smaller scale. For example, economists have shown that residential waterfront land prices increase with reductions in bacterial contamination (Leggett and Bockstael 2000), and that consumers have significant willingness to pay for the improvements in coastal water quality resulting from reductions in nutrient runoff (Morgan and Owens 2001). However, because a significant portion of shale gas and tight oil extraction occurs in remote areas away from population centers, the recreational and aesthetic value of water quality improvements may not be as large as what is estimated in these previous studies.

6. Conclusion and Recommendations

In this report, we have summarized the results of an RFF research effort to better understand the risks associated with on-site shale gas and tight oil wastewater storage and have evaluated regulations and technologies that can address these risks. The research effort was based on several approaches, including a review of the existing literature on the risks and mitigation options associated with wastewater storage in pits and tanks, an analysis of state databases on environmental incidents from oil and gas operations, and an informal survey of some industry stakeholders. While these information sources raised a large number of issues, we are led to six key conclusions regarding the current use of pits and tanks.

First, while tanks seem to offer more environmental protection than pits, we do not find clear evidence in the literature or in our analysis indicating that tanks should be required. There are some situations where pits are superior. Furthermore, there is some evidence that even on strict economic grounds, tanks are not always more expensive than pits, hence their growing popularity. Based on these conclusions, we question BLM's decision to require the use of tanks for hydraulic fracturing operations on federal and tribal lands.

Second, our literature review and analysis of state spill databases suggest that smaller and less frequent spills occur with tanks than with pits. However, tanks are not a magic bullet, and because of a lack of information on the overall number of pits and tanks, it is not possible to ascertain whether tanks lead to fewer and smaller spills because they are actually safer or

because a smaller number of them are currently being used. Ideally, specifications for pits and tanks would be integrated so that operators have the flexibility to choose the least-cost storage solution that meets given performance standards.

Third, our analysis of state spill databases indicates that pit overflows, tank overfills, and liner malfunctions are the most common causes for the release of shale gas and tight oil wastewater into the environment. This pattern in the data suggests that regulations and industry practices that target these three types of incidents would be effective in reducing the frequency of spills and, as a result, the risk of human and ecosystem exposure to potentially toxic substances in flowback and produced water.

Fourth, our survey of state regulations of on-site shale gas and tight oil wastewater storage reveals significant heterogeneity across states in the number and stringency of regulated elements. This heterogeneity is not necessarily a negative; differences in regulation between one state and another may be justified by differences in underlying geology, for example. However, the heterogeneity does provide an opportunity for states to learn from each other's experiences; states may benefit by adopting a regulation that has worked well in another state or by eliminating a regulation that has been ineffective elsewhere.

Fifth, we have identified several knowledge gaps that prevent us from gaining a comprehensive understanding of the risks that shale gas and tight oil wastewater storage in pits and tanks poses to human and ecological health. Specifically, future research would ideally seek new evidence regarding (a) the degree of exposure to substances in shale gas and tight oil wastewater through surface spills and leaching into groundwater; (b) the suitability of existing liner technology as specifically applied to pits storing flowback and produced water from hydraulic fracturing; and (c) the risks of shale gas and tight oil wastewater stored in pits and tanks on ecological systems.

Finally, our research has made clear that an easily searchable and sortable state database of spills is an invaluable tool that can improve our understanding of the risks associated with pits and tanks used in oil and gas production. The ability to search for specific incidents and sort them according to their parameters can also help regulators and decisionmakers in the oil and gas industry adopt policies, practices, and technologies that target the most frequent and severe spill types. The New Mexico OCD's database can serve as a model for this kind of useful information resource, although the utility of the system could be significantly improved by incorporating an inventory of existing pits and tanks so that the number of reported spills can be put into perspective. Ideally, states should adopt a uniform reporting standard that will allow for a comparison of the outcomes of different approaches to risk mitigation.

We conclude this report by providing a set of recommendations for regulators who are considering enacting new regulations on wastewater pits or who are seeking to modify existing regulations. The first five recommendations stem directly from the conclusions outlined above.

- **Recommendation #1:** Avoid outright bans of either pits or tanks.
- **Recommendation #2:** Instead, integrate specifications regarding fluid storage in pits with specifications regarding fluid storage in tanks so that operators have the flexibility to choose the least-cost storage solution that meets given performance standards.
- **Recommendation #3:** Promote further research that will generate evidence regarding (a) the degree of exposure to substances in shale gas and tight oil wastewater through surface spills and leaching into groundwater; (b) the suitability of existing liner technology as specifically applied to pits storing flowback and produced water from hydraulic fracturing; and (c) the risks of shale gas and tight oil wastewater stored in pits and tanks on ecological systems.
- **Recommendation #4:** Prioritize the development of policies, practices, and technologies that address pit overflows, tank overfills, and liner malfunctions.
- **Recommendation #5:** Promote uniform reporting and disclosure standards across states, and make these reports available on a searchable and sortable database.

We provide three additional recommendations based on principles of cost-effectiveness from the environmental economics literature.

- **Recommendation #6:** When possible, adopt a performance-based standard for each regulatory element.

Performance-based standards require pit and tank users to meet an emissions standard but allow the users to choose any available method to meet that standard. These standards are preferable to technology or design standards, which do not allow users to adjust to different extraction processes or local conditions. For example, pit liner performance standards should be based the liner's ability to ensure that the probability of leakage does not exceed a certain threshold. Users can then choose any liner material, thickness, permeability, and/or seam joining combination that achieves that probability threshold. Flexible regulations based on performance standards are also more likely to encourage innovation or adoption of new procedures that are more cost-effective while still meeting desired environmental targets.

- **Recommendation #7:** Develop permitting or authorization procedures based on characteristics of the fluids stored.

Such procedures will ensure that the performance-based standards required of a pit are consistent with the risks associated with the type of fluid stored in the pit. Note that permitting and authorization based on fluid characteristics or function may lower compliance costs by reducing requirements for lower-risk fluids.

- **Recommendation #8:** Identify regulatory elements that involve relatively homogeneous costs across producers.

Although many regulations may involve costs to producers that vary significantly depending on local geologic, hydrologic, and climatic conditions, the costs associated with a subset of the risk mitigation strategies discussed in Section 4 of this report are likely to be relatively uniform across producers. One example is fencing and netting requirements, which require the same materials and installation procedures regardless of where the pit is located or the type of fluid contained in the pit. Another example is a set of standards for truck drivers who handle fluids from pits and tanks. In this case, uniform standards regarding driver qualifications and limits on consecutive hours worked are likely to be sufficient for reducing the risk of contaminant releases from a wide range of pit and tank types and locations. When considering new regulations or a modification of existing regulations, these pit elements that involve homogeneous costs across producers may be a good starting point, given their relative simplicity and ease of enforcement.

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Tables and Figures

Table 1. Pollutant Concentrations in Oil and Gas Wastewater in Pennsylvania—VOCs

Material	Range detected in produced water pit in Pennsylvania (mg/L)	Range detected in Marcellus Shale waste constituents (mg/L)	MRL (mg/kg/day)	EPA maximum contaminant level goal (mg/L)
Benzene	0.0006–0.25	0.001–1.3	0.00005 (Chronic)	0
Toluene	0.001–0.27	NR	0.8 (Acute) 0.02 (Intermediate)	1
Ethylbenzene	0.0013–0.049	NR	0.4 (Intermediate)	0.7
Naphthalene	0.001–0.076	NR	NR	NR
Xylene	0.0011–1.78	0.0047–0.11	1 (Acute) 0.4 (Intermediate) 0.2 (Chronic)	10
	(Gilius et al. 1994)	(Shih et al. 2015)	(ATSDR 2013)	(EPA 2009)

Note: NR = not reported

Table 2. Pollutant Concentrations in Oil and Gas Wastewater in Pennsylvania—Metals

Material	Range detected in produced water pit or completion/workover waste (mg/L)	Range detected in Marcellus Shale waste constituents (mg/L)	MRL, oral (mg/kg/day)	EPA maximum contaminant level goal (mg/L)
Antimony	0.1–0.148 ^b	NR	NR	0.006
Arsenic	<0.01–.031 ^a	NR	0.005 (Acute) 0.0003 (Chronic)	0
Barium	0.07–19.1 ^a	0.061–12,000	0.2 (Intermediate) 0.2 (Chronic)	2
Beryllium	0.0047–0.0251 ^b	NR	0.002 (Chronic)	0.004
Cadmium	<0.05 ^a	NR	0.0005 (Intermediate) 0.0001 (Chronic)	0.005
Chromium	<0.05 ^a	0.00084–2.2	0.005 (Intermediate) 0.0009 (Chronic)	0.1
Copper	0.0068–6.07 ^b	0.0065–18	0.01 (Acute) 0.01 (Intermediate)	1.3
Lead	<0.1–0.27 ^a	NR	NR	0
Mercury	0.006 ^b	NR	NR	0.002
Selenium	<0.01–0.016 ^a	NR	0.005 (Chronic)	0.5
Thallium	0.0673 ^b	NR	NR	0.0005
	^a (Gilius et al. 1994) ^b (EPA 2000); samples taken from completion and workover wastes, not necessarily from pits	(Shih et al. 2015)	(ATSDR 2013)	(EPA 2009)

Note: NR = not reported

Table 3. Volumes Spilled and Lost from Pits and Tanks by Material Spilled, in Barrels (2000–2014)

Pits					
Material spilled	Number of spills	Volume spilled (mean)	Volume spilled (median)	Volume lost (mean)	Volume lost (median)
Produced water	41	260.1	30	244.8	9
Drilling mud/fluid	28	153.3	35	103.8	20
Brine water	10	912.6	82.5	507	45
Crude oil	10	117.9	17.5	114.63	10
Condensate	1	10	10	5	5
Other	16	1,148.3	62.5	1,138.5	30
TOTAL	106	411.7	35	352.6	13.5
Tanks					
Material spilled	Number of spills	Volume spilled (mean)	Volume spilled (median)	Volume lost (mean)	Volume lost (median)
Produced water	19	123.8	30	59.9	7
Crude oil	12	48.6	20	11.3	4.5
Acid	6	52.5	45	40	45
Brine water	5	117.8	20	117.8	20
Gelled brine (frac fluid)	5	74.2	49	65	9
Drilling mud/fluid	4	25	20	10.3	8
Chemical (unspecified)	2	109	109	109	109
Basic sediment and water	1	91	91	91	91
Other	8	291.8	82.5	118.8	7.5
TOTAL	62	119.6	30	53.9	7

Table 4. Volumes Spilled and Lost from Pits and Tanks by Spill Cause, in Barrels (2000–2014)

Volumes spilled and lost from pits by spill cause (barrels)					
Spill cause	Number of spills	Volume spilled (mean)	Volume spilled (median)	Volume lost (mean)	Volume lost (median)
Overflow	35	41.7	25	19.6	5
Liner malfunction	28	771.1	95	735.8	45
Improper closure or reclamation	6	64.5	12.5	64.3	12.5
Berm failure	4	50	52.5	27.5	30
Unlined pit	3	360	360	360	360
Blowover	2	11	11	6	6
Sinkhole	2	5,050	5,050	5,050	5,050
Unidentified or undocumented loss	26	338.7	18.5	169.5	10
TOTAL	106	411.7	35	352.6	13.5
Volumes spilled and lost from tanks by spill cause (barrels)					
Spill cause	Number of spills	Volume spilled (mean)	Volume spilled (median)	Volume lost (mean)	Volume lost (median)
Leak	27	80	40	64	20
Overfilling	17	106	32	21	6
Collapse	2	275	275	275	275
Lightning strike	2	46	46	46	46
Vandalism	2	925	925	425	425
Fire	1	297	297	19	19
Unidentified or undocumented loss	11	19	10	13	4
TOTAL	62	112	36	60	15

Table 5. Texas Railroad Commission Estimates of Pit Liner Costs per Square Foot

Plastic liners	2002\$		2014\$	
	Low estimate	High estimate	Low estimate	High estimate
Reserve pits				
12-mil nonreinforced	\$0.08	\$0.27	\$0.11	\$0.36
12-mil reinforced	\$0.10	\$0.29	\$0.13	\$0.38
Workover pits				
12-mil nonreinforced	\$0.06	\$1.08	\$0.08	\$1.43
12-mil reinforced	\$0.07	\$1.17	\$0.09	\$1.55

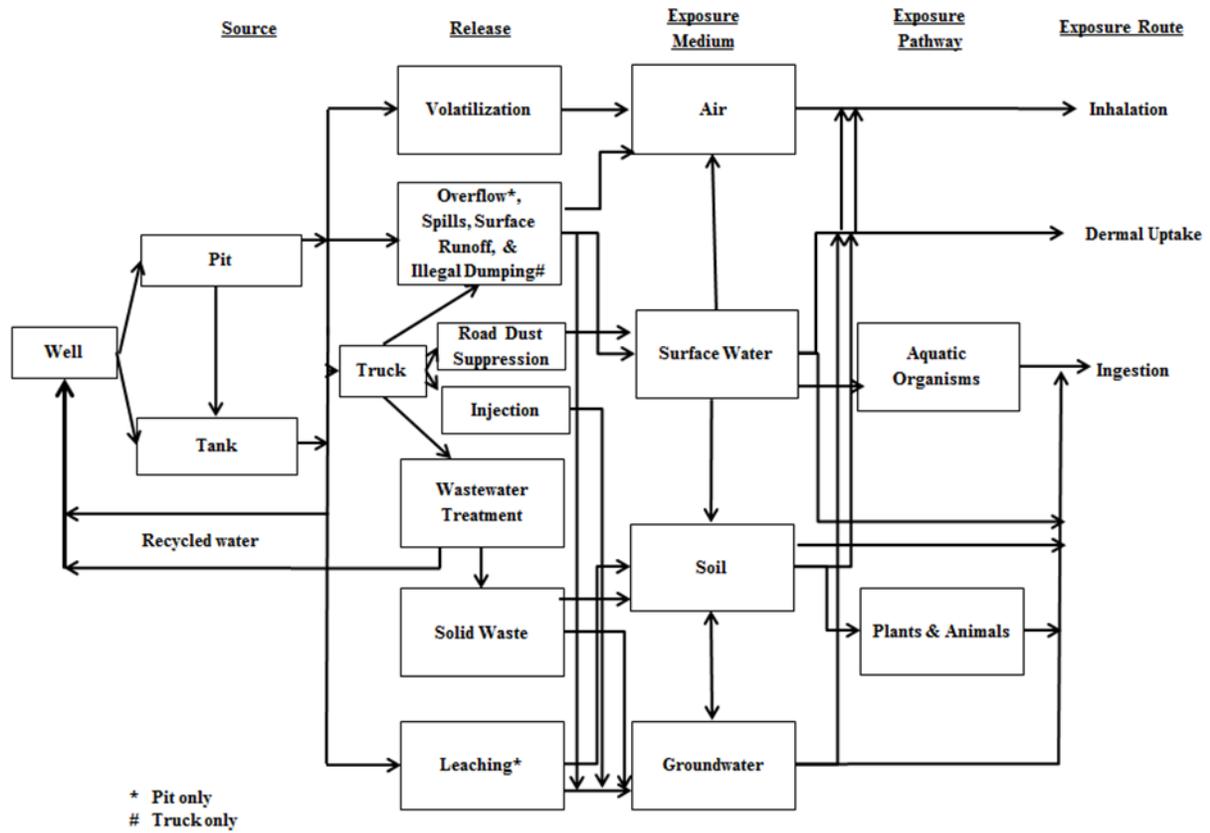
Note: Estimates obtained from response to comments on proposed rule in Texas Administrative Code, Title 16, Chapter 4, Subchapter B. Oil and Gas Division, Railroad Commission of Texas (September 20, 2002).

Table 6. Quantified Reported Releases of Oil and Saltwater from Oil/Gas Production Activities in Oklahoma, Classified by Reported Damage Caused

	Oil		Saltwater	
	Reports	Total volume (bbl)	Reports	Total volume (bbl)
Surface water	609	74,900	346	243,600
Crop/stock	176	32,600	185	104,600
Soil injury	22	26,300	16	44,400
Erosion	5	2,600	3	10,300
Groundwater	1	2,400	2	176,300
Wildlife	2	210	1	28,500

Source: Fisher and Sublette (n.d.)

Figure 1. Summary of Contaminant Release Mechanisms and Exposure Pathways Associated with Pits



Note: This figure was adapted from Johnson et al. (2003) to depict additional mechanisms and pathways identified in our literature survey.

Figure 2. Time Series Plot of Nonzero Volume Spills from Pits and Tanks as Reported to New Mexico’s Oil Conservation Division (OCD)

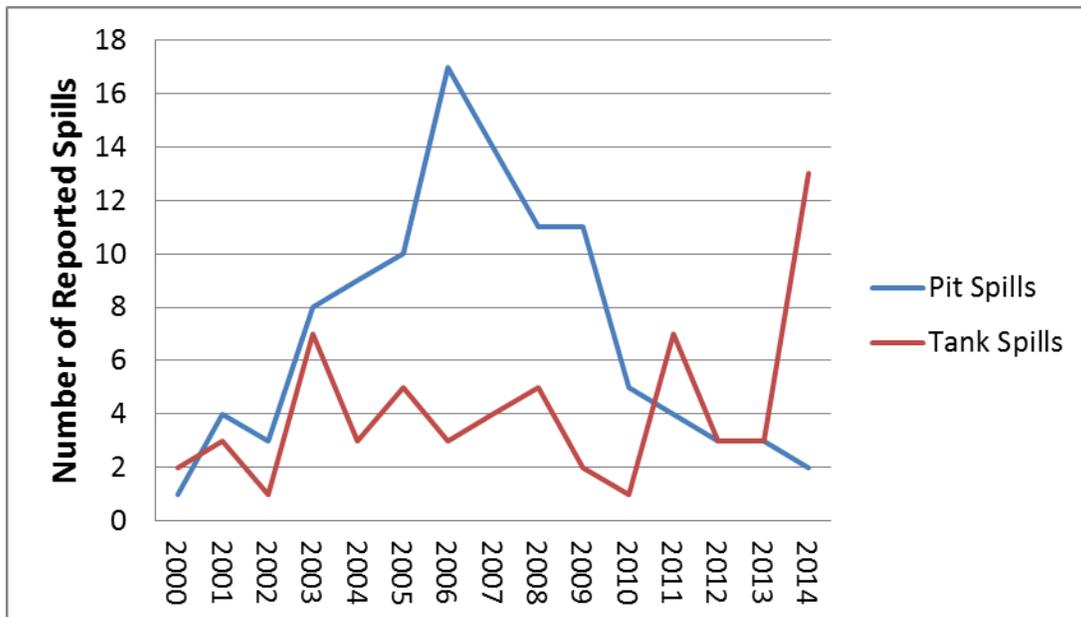


Figure 3. Distribution of Spill Volumes from Pits (All Spills) as Reported to New Mexico’s OCD

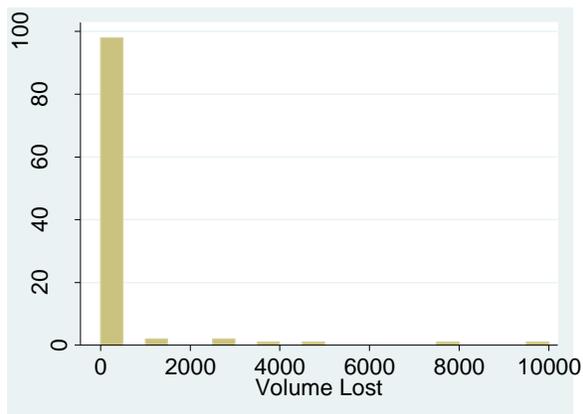


Figure 4. Distribution of Spill Volumes for Spills ≤ 200 BBL (83% of Spills) from Pits as Reported to New Mexico’s OCD

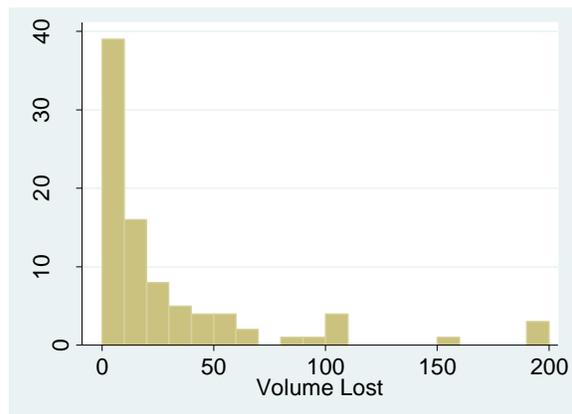


Figure 5. Distribution of Loss Volumes from Pits (all spills) as Reported to New Mexico's OCD

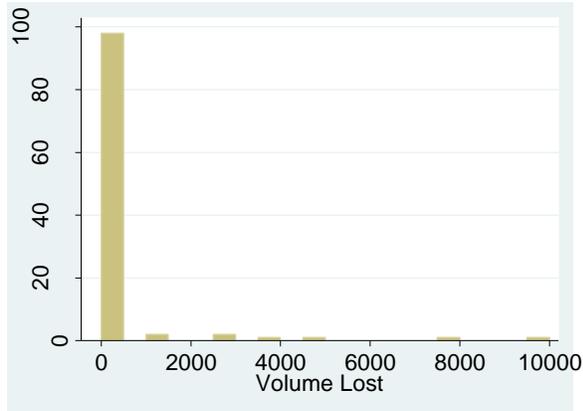


Figure 6. Distribution of Loss Volumes for Spills ≤ 200 BBL (83% of Spills) from Pits as Reported to New Mexico's OCD

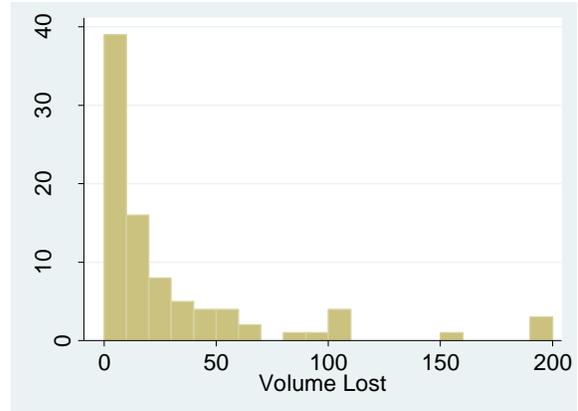


Figure 7. Distribution of Spill Volumes from Tanks (all spills) as Reported to New Mexico's OCD

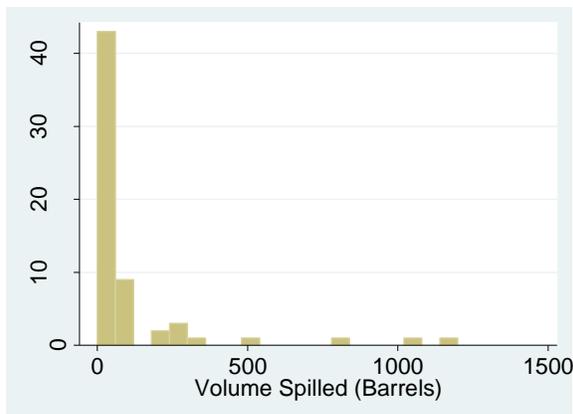


Figure 8. Distribution of Spill Volumes for Spills <100 BBL (82% of Spills) from Tanks as Reported to New Mexico's OCD

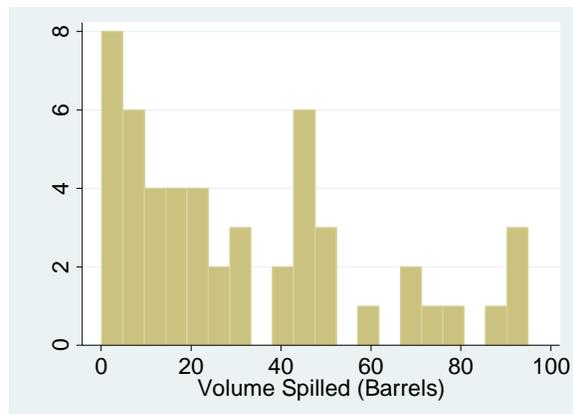


Figure 9. Distribution of Loss Volumes from Tanks (All Spills) as Reported to New Mexico's OCD

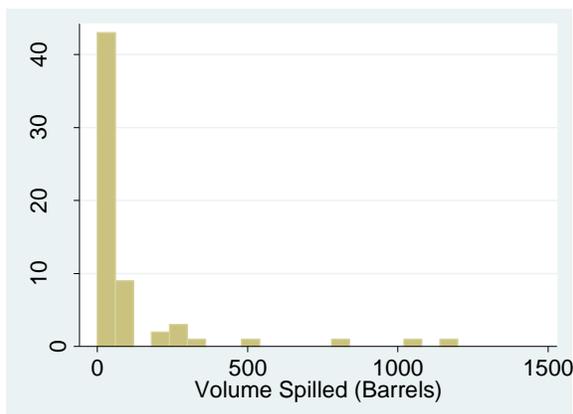


Figure 10. Distribution of Loss Volumes for Spills <100 BBL (82% of Spills) from Tanks as Reported to New Mexico's OCD

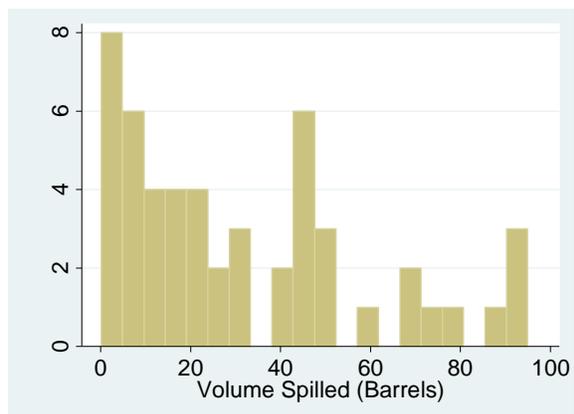


Figure 14. Map of State-Level Regulations on Pit Liner Thickness Requirements

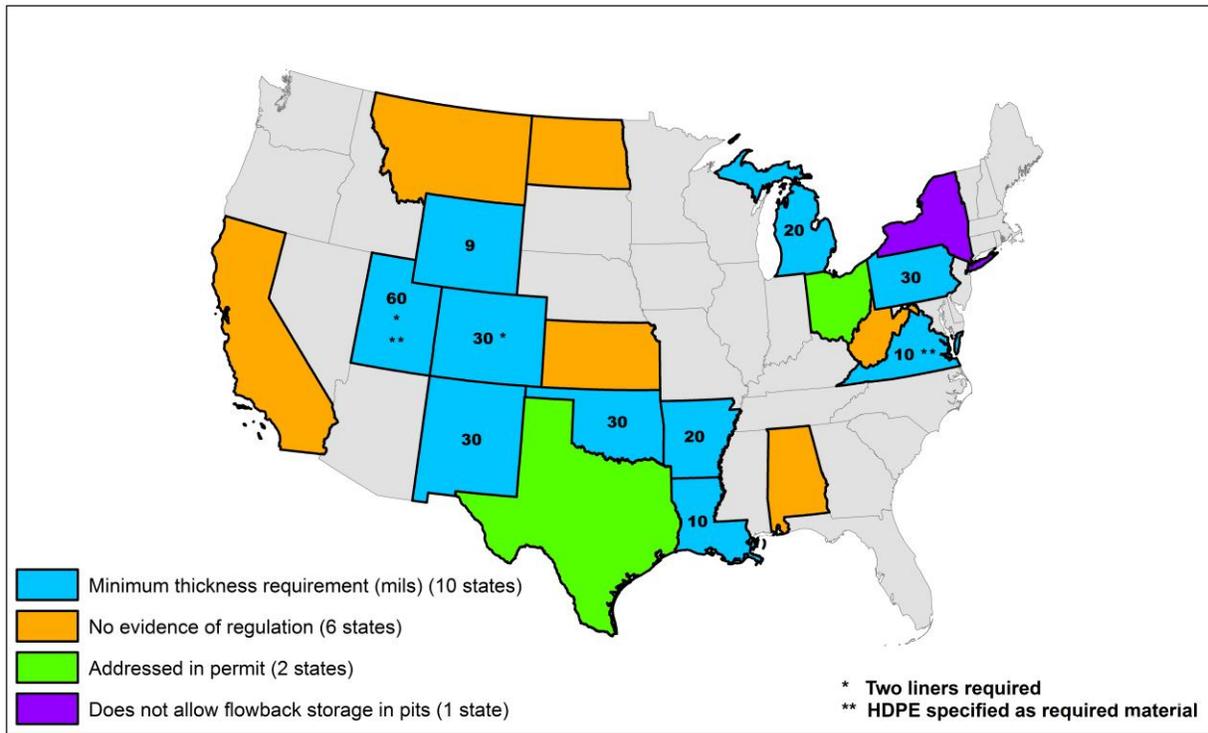


Figure 15. Map of State-Level Regulations on Pit Liner Coefficients of Hydraulic Conductivity

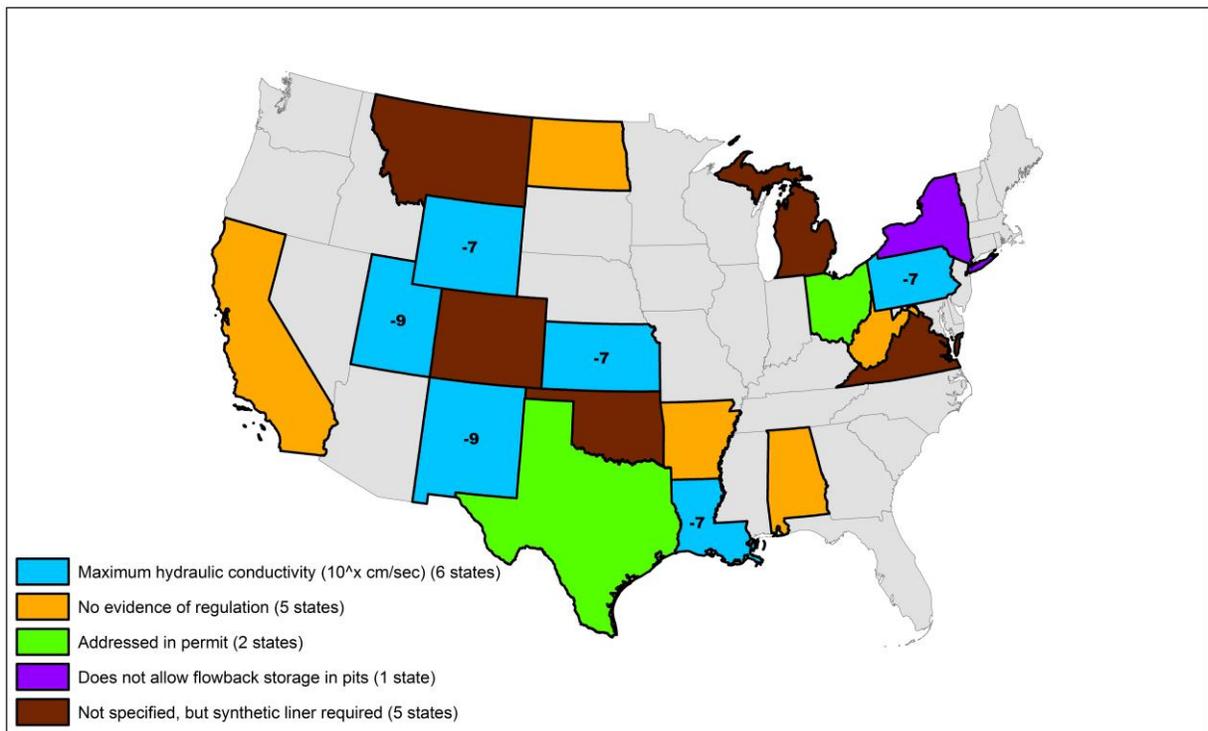


Figure 16. Map of State-Level Regulations on Pit Freeboard Requirements

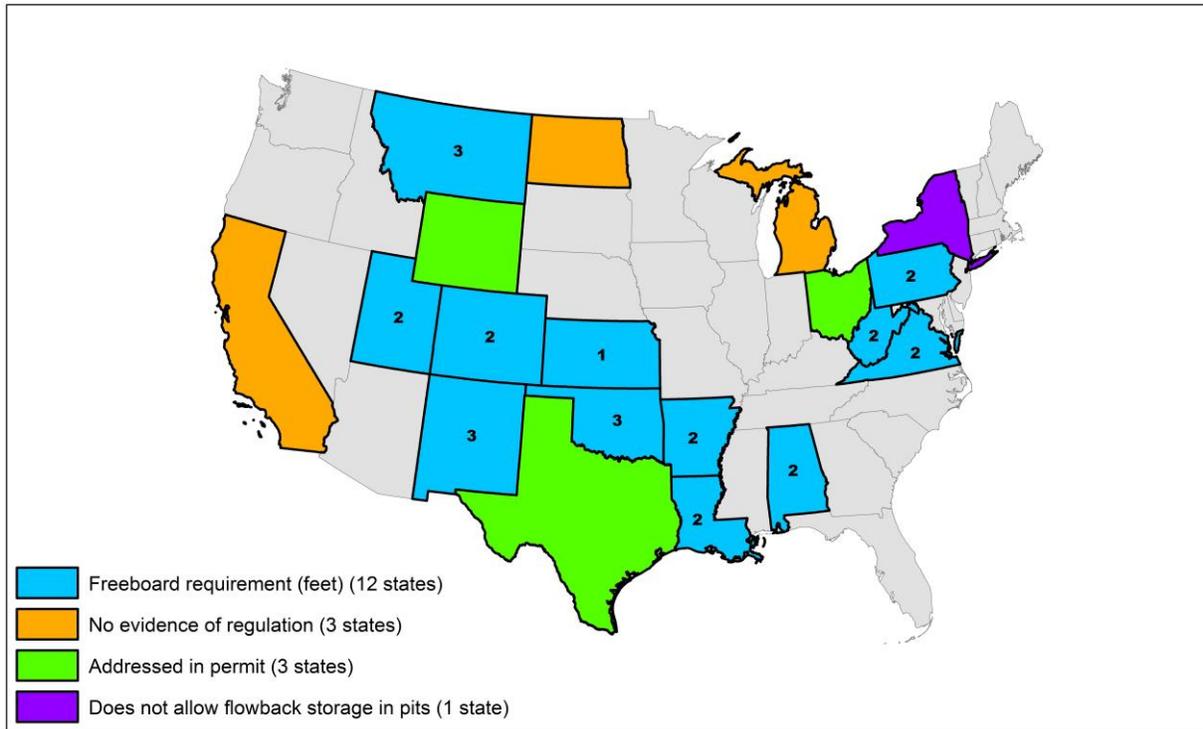


Figure 17. Map of State-Level Regulations on Spill Reporting Requirements in Hours

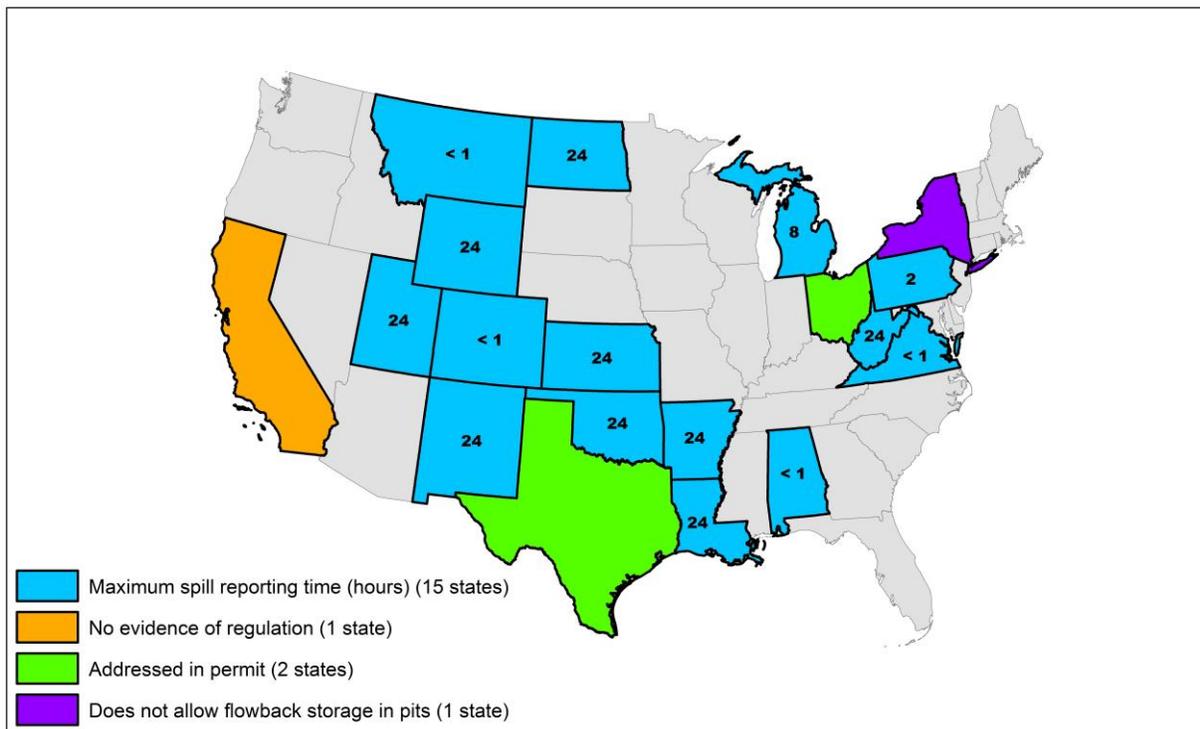


Figure 18. New Mexico's Pit Permit Application

Form C-144
Revised August 1, 2011

State of New Mexico
Energy Minerals and Natural Resources
Department
Oil Conservation Division
1220 South St. Francis Dr.
Santa Fe, NM 87505

For temporary pits, closed-loop systems, and below-grade tanks, submit to the appropriate NMOCD District Office.
For permanent pits and exceptions submit to the Santa Fe Environmental Bureau office and provide a copy to the appropriate NMOCD District Office.

Pit, Closed-Loop System, Below-Grade Tank, or Proposed Alternative Method Permit or Closure Plan Application

Type of action: Permit of a pit, closed-loop system, below-grade tank, or proposed alternative method
 Closure of a pit, closed-loop system, below-grade tank, or proposed alternative method
 Modification to an existing permit
 Closure plan only submitted for an existing permitted or non-permitted pit, closed-loop system, below-grade tank, or proposed alternative method

Instructions: Please submit one application (Form C-144) per individual pit, closed-loop system, below-grade tank or alternative request

Please be advised that approval of this request does not relieve the operator of liability should operations result in pollution of surface water, ground water or the environment. Nor does approval relieve the operator of its responsibility to comply with any other applicable governmental authority's rules, regulations or ordinances.

Operator: _____ OGRID #: _____
 Address: _____
 Facility or well name: _____
 API Number: _____ OCD Permit Number: _____
 U/L or Qtr: _____ Section _____ Township _____ Range _____ County: _____
 Center of Proposed Design: Latitude _____ Longitude _____ NAD: 1927 1983
 Surface Owner: Federal State Private Tribal Trust or Indian Allotment

Pit: Subsection F or G of 19.15.17.11 NMAC
 Temporary: Drilling Workover
 Permanent Emergency Cavitation P&A
 Lined Unlined Liner type: Thickness _____ mil LLDPE HDPE PVC Other _____
 String-Reinforced
 Liner Seams: Welded Factory Other _____ Volume: _____ bbl Dimensions: L _____ x W _____ x D _____

Closed-loop System: Subsection H of 19.15.17.11 NMAC
 Type of Operation: P&A Drilling a new well Workover or Drilling (Applies to activities which require prior approval of a permit or notice of intent)
 Drying Pad Above Ground Steel Tanks Hand-off Bins Other _____
 Lined Unlined Liner type: Thickness _____ mil LLDPE HDPE PVC Other _____
 Liner Seams: Welded Factory Other _____

Below-grade tank: Subsection I of 19.15.17.11 NMAC
 Volume: _____ bbl Type of fluid: _____
 Tank Construction material: _____
 Secondary containment with leak detection Visible sidewalls, liner, 6-inch lift and automatic overflow shut-off
 Visible sidewalls and liner Visible sidewalls only Other _____
 Liner type: Thickness _____ mil HDPE PVC Other _____

Alternative Method:
 Submittal of an exception request is required. Exceptions must be submitted to the Santa Fe Environmental Bureau office for consideration of approval.

Fencing: Subsection D of 19.15.17.11 NMAC (Applies to permanent pits, temporary pits, and below-grade tanks)
 Chain link, six feet in height, two strands of barbed wire at top (Required if located within 1000 feet of a permanent residence, school, hospital, institution or church)
 Four foot height, four strands of barbed wire evenly spaced between one and four feet
 Alternate: Please specify _____

Netting: Subsection E of 19.15.17.11 NMAC (Applies to permanent pits and permanent open top tanks)
 Screens Netting Other _____
 Monthly inspections (If netting or screening is not physically feasible)

Signs: Subsection C of 19.15.17.11 NMAC
 12"x24", 2" lettering, providing Operator's name, site location, and emergency telephone numbers
 Signed in compliance with 19.15.16.8 NMAC

Administrative Approvals and Exceptions:
 Justifications and/or demonstrations of equivalency are required. Please refer to 19.15.17 NMAC for guidance.
Please check a box if one or more of the following is requested, if not leave blank:
 Administrative approval(s): Requests must be submitted to the appropriate division district or the Santa Fe Environmental Bureau office for consideration of approval.
 Exception(s): Requests must be submitted to the Santa Fe Environmental Bureau office for consideration of approval.

Siting Criteria (regarding permitting): 19.15.17.10 NMAC
Instructions: The applicant must demonstrate compliance for each siting criteria below in the application. Recommendations of acceptable source material are provided below. Requests regarding changes to certain siting criteria may require administrative approval from the appropriate district office or may be considered an exception which must be submitted to the Santa Fe Environmental Bureau office for consideration of approval. Applicant must attach justification for request. Please refer to 19.15.17.10 NMAC for guidance. Siting criteria does not apply to drying pads or above-grade tanks associated with a closed-loop system.

Ground water is less than 50 feet below the bottom of the temporary pit, permanent pit, or below-grade tank. - NM Office of the State Engineer - iWATERS database search; USGS; Data obtained from nearby wells	<input type="checkbox"/> Yes <input type="checkbox"/> No
Within 300 feet of a continuously flowing watercourse, or 200 feet of any other significant watercourse or lakebed, sinkhole, or plays lake (measured from the ordinary high-water mark). - Topographic map; Visual inspection (certification) of the proposed site	<input type="checkbox"/> Yes <input type="checkbox"/> No
Within 300 feet from a permanent residence, school, hospital, institution, or church in existence at the time of initial application. (Applies to temporary, emergency, or cavitation pits and below-grade tanks) - Visual inspection (certification) of the proposed site; Aerial photo; Satellite image	<input type="checkbox"/> Yes <input type="checkbox"/> No <input type="checkbox"/> NA
Within 1000 feet from a permanent residence, school, hospital, institution, or church in existence at the time of initial application. (Applies to permanent pits) - Visual inspection (certification) of the proposed site; Aerial photo; Satellite image	<input type="checkbox"/> Yes <input type="checkbox"/> No <input type="checkbox"/> NA
Within 500 horizontal feet of a private, domestic fresh water well or spring that less than five households use for domestic or stock watering purposes, or within 1000 horizontal feet of any other fresh water well or spring, in existence at the time of initial application. - NM Office of the State Engineer - iWATERS database search; Visual inspection (certification) of the proposed site	<input type="checkbox"/> Yes <input type="checkbox"/> No
Within incorporated municipal boundaries or within a defined municipal fresh water well field covered under a municipal ordinance adopted pursuant to NMSA 1978, Section 3-27-3, as amended. - Written confirmation or verification from the municipality; Written approval obtained from the municipality	<input type="checkbox"/> Yes <input type="checkbox"/> No
Within 500 feet of a wetland. - US Fish and Wildlife Wetland Identification map; Topographic map; Visual inspection (certification) of the proposed site	<input type="checkbox"/> Yes <input type="checkbox"/> No
Within the area overlying a subsurface mine. - Written confirmation or verification or map from the NM ENMRD-Mining and Mineral Division	<input type="checkbox"/> Yes <input type="checkbox"/> No
Within an unstable area. - Engineering measures incorporated into the design; NM Bureau of Geology & Mineral Resources, USGS, NM Geological Society; Topographic map	<input type="checkbox"/> Yes <input type="checkbox"/> No
Within a 100-year floodplain. - FEMA map	<input type="checkbox"/> Yes <input type="checkbox"/> No

Figure 19. Number of Elements Regulated by State

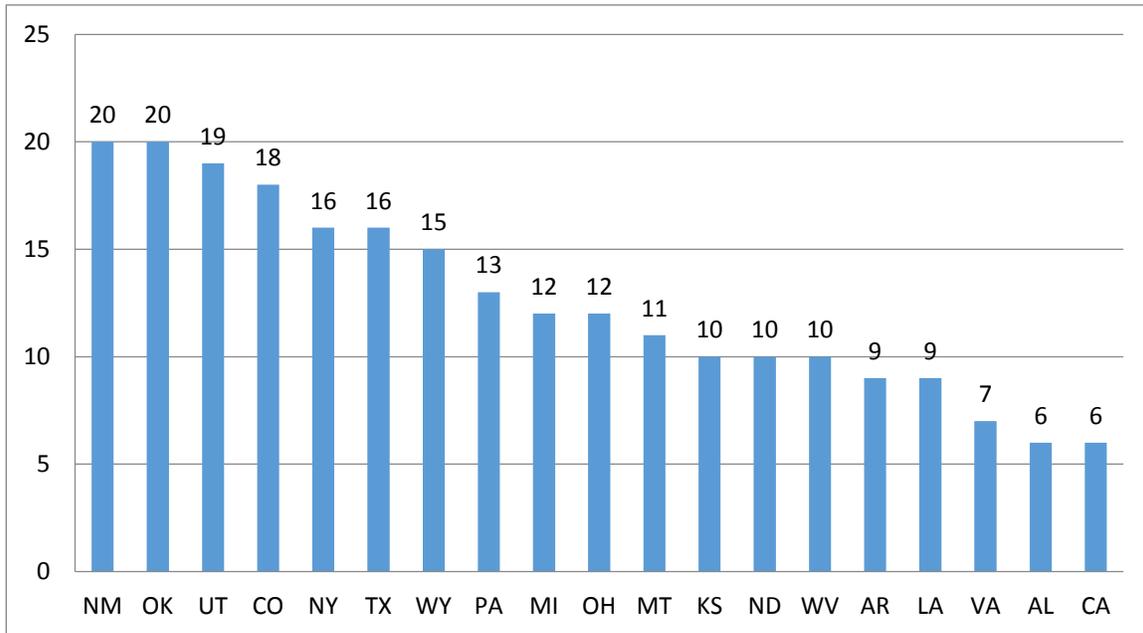


Figure 20. Average Stringency of Quantitatively Regulated Elements

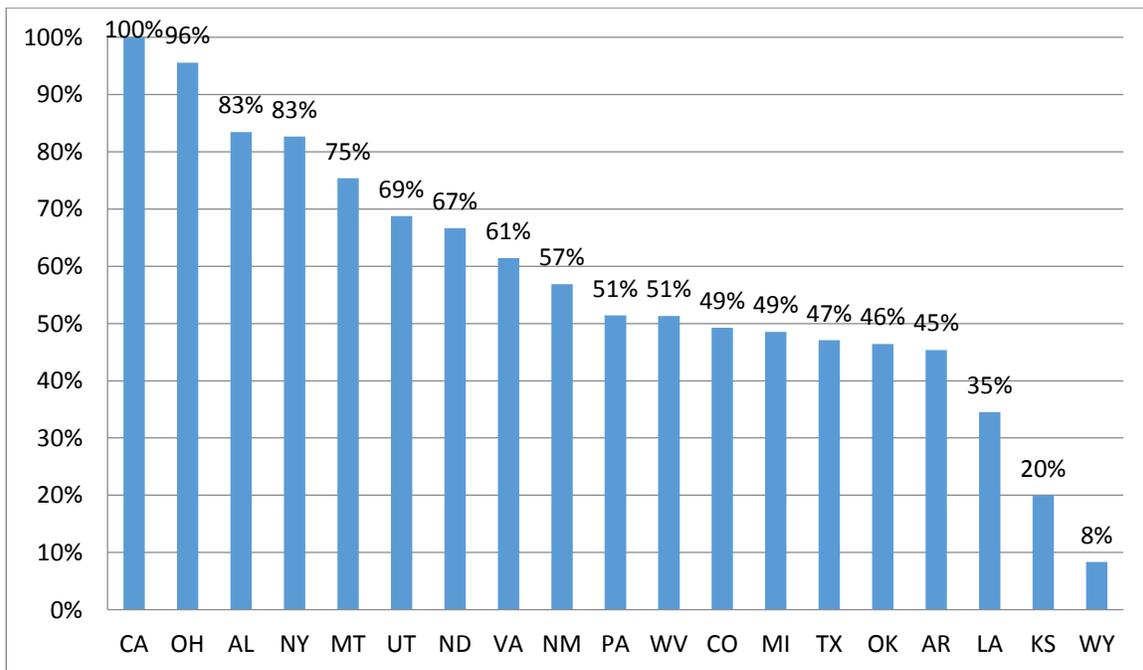


Figure 21. Average “Adjusted” Stringency of Quantitatively Regulated and Unregulated Elements

