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Addressing air and water concerns: State policy opportunities in unconventional oil and gas

A Woodrow Wilson School Graduate Policy Workshop

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TABLE OF CONTENTS

EXECUTIVE SUMMARY

Recent improvements in unconventional oil and gas drilling and production technologies have transformed the United States into the world's largest natural gas producer as well as the fastest growing oil producer (Ratner & Tiemann, 2014). The Department of Energy estimates that natural gas production in the United States will grow by 56 percent between 2014 and 2040. Unconventional gas production from shale deposits will be responsible for three quarters of this growth. Furthermore, from 2020 onward, oil production from unconventional sources is projected to account for over 50% of total US oil production (Energy Information Administration, 2014a).

The rapidly evolving landscape of unconventional oil and gas development brings new opportunities and challenges for states trying to capitalize on the benefits of new fossil energy production. Despite its economic promise, unconventional oil and gas development presents risks to air quality and water resources. Gaseous emissions from unconventional oil and gas production, as well as gas transmission in general, include potent greenhouse gases and volatile organic compounds that cause smog and local health hazards. Water withdrawals for hydraulic fracturing can add to water stress in already dry areas, and both drilling and wastewater management present the risk of contaminating important sources of freshwater.

This report outlines an array of policy recommendations that states can consider for reducing the impacts of unconventional oil and gas development and distribution. Chapter 1 provides an overview of the unconventional oil and gas development process. Chapters 2 and 3 describe the risks associated with unconventional oil and gas development in terms of gaseous emissions (chapter 2) and water scarcity and contamination (chapter 3). Each of these chapters reviews the technical approaches to addressing these risks and outlines how state-level policy can encourage the responsible development of the industry in a cost effective manner. Chapter 4 lays out specific recommendations for state policy makers in three main areas: key stakeholder engagement to assist the implementation of effective regulations; adaptive management frameworks to encourage continual improvement of state regulations as technology and research evolve; and finally recommendations on monitoring and enforcement to ensure regulations are effective and efficient.

Reducing Gaseous Emissions

Natural gas leakage can occur throughout the entire unconventional oil and gas development and production process, from well completions, through to the production, processing, transmission, and distribution of the oil and gas. These gaseous emissions have significant implications for health and climate outcomes. Natural gas leakage has been found to contribute to increased levels of air pollutants that are associated with increased morbidity and mortality risks (PSE Health Energy, 2014). Furthermore, although natural gas, when burned, produces less carbon dioxide per unit of energy than other fossil fuels (coal for generating electricity or petroleum products for vehicles), even a relatively small leakage rate (3.2% for gas used in electricity production or 1% including transport) of natural gas during production and transmission may result in a larger climate impact than other fossil fuels (Alvarez et al., 2012).

Recently proposed modifications to allowable surface ozone concentrations by the EPA have increased the importance of proactively addressing natural gas emissions. Surface ozone, of which natural gas is a precursor, is currently regulated by the National Ambient Air Quality Standards (NAAQS). States that fall outside of the NAAQS regulations must address non-compliance through State Implementation Plans (SIPs). In contrast, **states that pre-emptively address the tightening of the NAAQS requirements through stricter air regulations, including direct methane control, may find such an approach beneficial to "get ahead of the curve"** and avoid more drastic and less flexible requirements that would likely become part of an SIP.

Importantly, each step of the unconventional oil and gas development process presents a unique set of challenges for reducing emissions. Critically, there are many low-cost technological changes that can be made to substantially reduce gaseous emissions.

Emission Reduction Strategies are Cost Effective (chapter 2, page 16): Over 20 of the highest methane emission sources can be addressed at a net cost saving to industry. Savings are even greater if economy-wide benefits are considered.

The following set of recommendations highlights some key cost effective emission reduction possibilities, and underscores the need for policy interventions across the oil and gas development cycle:

Require Leak Detection and Repair Programs (chapter 2, page 12): Periodic, comprehensive inspection of equipment across the oil and gas sector is the most effective method to locate methane leaks. Although there are federal regulations requiring detection and repair programs in parts of the oil and gas industry, the laws are narrowly focused on equipment in the processing sector. Extending this practice to include all equipment throughout the complete oil and natural gas process, including the production and transmission sectors, can help decrease aggregate methane leakage rates by 14% of total methane leakage from unconventional development (ICF International, 2014).

Require Installation of Low or No-Bleed Controllers (chapter 2, page 13): Use of low bleed controllers can reduce emissions from equipment by an order of magnitude. Requiring replacement of existing high and intermittent bleed pneumatic devices with low- or no-bleed devices can be achieved at a net cost benefit to the gas producer (ICF International, 2014). Where electricity is available, electrically driven (no-bleed) devices should be required.

Phase Out Pneumatically Driven Pumps (chapter 2, page 13): Replacement of Kimray pumps with electrically driven pumps on glycol dehydration units results in a significant reduction in emissions at a significant cost saving to industry (ICF International, 2014). In addition, other pneumatically driven pumps including chemical injection pumps, can be replaced with solar driven models at very low cost.

Extend Reduced Emissions Completions, or no venting requirements to all wells (chapter 2, page 14): Although EPA regulations now require that gas wells use Reduced Emission Completions, this requirement should be extended to include oil wells where economically feasible. Where infrastructure is not available or the economics cannot be justified, flaring rather than venting of gas should be a requirement. These are both cost effective measures (ICF International, 2014) with much broader environmental benefits.

Require Installation of Vapor Recovery Units on Centrifugal Compressors (chapter 2, page 14): Compressors with wet seals can be fitted with Vapor Recovery Units to redirect the vented seal emissions back to the process or to flare. This is a highly cost effective measure to reduce one of the most significant sources of emissions.

Introduce financial incentives for Local Distribution Companies (LDCs) to decrease fugitive emissions (chapter 2, page 16): In most states, current rules allow LDCs to recoup the revenue lost from methane leaks in the distribution system by charging gas consumers higher prices (Costello, 2013). Recently, **New York** has attempted to address this issue by imposing penalties on LDCs for exceeding a negotiated, allowable leakage rate and returning the collected fees to ratepayers (Cleveland, 2012). States should consider introducing similar initiatives to incentivize LDCs to proactively repair leaking infrastructure.

Require the full value of the natural gas stream to be considered when making economic assessments of pollution reduction measures (chapter 2, page 14): In rare cases where states require economic justification for not undertaking a certain emission or waste reduction measure, often the value of the gas is only considered to be that of the base methane, and does not include other high value components that are produced with the gas, such as condensate and natural gas liquids. Including these in the economic calculations can have a significant impact on the cost effectiveness of a given measure. Another method to encourage minimization of waste is application of a tax on wasted (flared or vented) gas, commensurate with the value of the gas if it was sold.

Other recommendations, such as requiring operators to use best management practices to minimize emissions during liquids unloading, can be implemented at low cost and are discussed in further detail in this report.

The following table summarizes a subset of policy opportunities to reduce methane emissions from unconventional oil and gas development. The table highlights states that have currently implemented these practices, and provides estimates of the financial costs to businesses and emission reduction potential of each initiative.

<u>Reducing Water Impacts</u>

Unconventional oil and gas development presents risks to water availability, as well as to water quality. Water quality (contamination) issues can be divided into two areas: risks generated by subsurface activities and risks due to surface activities. Each of these areas presents policymakers with distinct challenges, requiring a broad range of policy interventions to address effectively. The following set of recommendations highlights important policy opportunities:

Air Recommendations	Leading States	Methane Reduction Potential (% of total emissions)	Economic Cost to Business ($/1000 Cubic ft of Methane Reduced)
Require Leak Detection and Repair (LDAR) Programs, non-distribution segment **(Page 15)**	CO, OH, WY	13%	-$3.03 to 3.51, depending on segment
Require LDAR program, distribution segment **(Page 15)**	CA	2%	$19.75
Require use of centrifugal compressor wet seals and reciprocating compressor rod packing **(Page 17)**	CO (limited scope)	6%	-$3.07 to $6.11
Require installation of low or no-bleed pneumatic equipment **(Page 17)**	CO (pneumatic devices)	9%	-$4.05 to $1.72
Require use of condensate tank and oil tank Vapor Recovery Units (VRU) **(Page 17)**		1%	$0.21 to $0.33
Extend flaring requirement to all wells and require stranded gas venting from oil wells **(Page 18)**	CO, NE, ND, OH, SD, UT, WY	4%	$0.30 to $2.13
Introduce financial incentives for LDCs **(Page 20)**	NY, MA	Uncertain	Dependent on negotiated rate

Source: ICF International 2014

Require highest standards of casing and cementing for well integrity (chapter 3, page 22): The most likely subsurface pathway through which groundwater may become contaminated is wells with compromised integrity (Gorody, 2012). Best casing and cementing practices can minimize well integrity risks and should be required. In support of these standards, casing and cementing plans that demonstrate suitable design for the particular local subsurface conditions should be submitted as part of well drilling permit applications, and casing and cementing reports should be submitted following completion. Comprehensive evaluation and remediation of well integrity should be required during well casing and cementing and throughout well life.

Require best management practices for hydraulic fracturing (chapter 3, page 22): Hydraulic fracturing can be conducted safely when best management practices are employed. These practices include a comprehensive area-of-review risk assessment before fracturing, pre-drill water testing and periodic post-completion testing. All fracturing fluid chemical additives should be disclosed, including chemical family names for trade secret additives.

Enhance approvals and disclosure (chapter 3, page 23): States need evidence of, or the ability to observe, critical aspects of well development to assess and ensure environmental performance. Regulators should be notified at crucial stages (e.g. well casing and cementing) to enable inspectors to be present, hydraulic fracturing should have additional approval to well drilling, and evaluation of well integrity should be required regularly, with any deficiencies reported to regulators and remediated.

Maximize recycling and reuse of hydraulic fracturing wastewater (chapter 3, page 19): Easing regulations for on-site reuse and wastewater transfers between operators can encourage recycling and reduce volumes of hydraulic fracturing wastewater requiring treatment and disposal.

Implement best management practices for storage tanks and pits (chapter 3, page 27): To minimize the risk of surface water contamination through spills and leaks of hydraulic fracturing wastewater, storage pits should have pit liners and freeboard (extra pit wall height above fluid level), while storage tanks should have secondary containment and corrosion-resistant construction materials.

Require appropriate treatment prior to surface water disposal (chapter 3, page 27): Disposal to publicly owned treatment works (POTWs) should be banned, as such facilities are ill-equipped to handle hydraulic fracturing wastewater. Centralized waste treatment facilities (CWTs), after appropriate treatment upgrades, could provide proper oversight of treatment and disposal to surface waters. States could also regulate specific contaminants to address regulatory gaps created by federal exemptions, such as unregulated non-diesel hydraulic fracturing fluid additives containing benzene, toluene, ethylbenzene, and xylene (BTEX), as well as manage particular contaminants that are relevant to each state. States could also avoid re-introducing contaminants to surface waters by regulating proper management and disposal of residuals, such as brines and sludges.

The following table summarizes water policy recommendations, highlighting states that currently exhibit leading practices and providing estimates for the economic cost of the regulation for businesses, where available.

Water Recommendations	Leading States	Economic Costs to Business
Require high standards for well integrity **(Page 29)**	OH	Low relative to total well costs*
Best management practices for hydraulic fracturing **(Page 30)**	IL	Uncertain
Wastewater treatment best management practices **(Page 36)**	Open opportunity	Varies depending on treatment upgrades necessary
Maximize recycling and reuse of fracturing wastewater **(Page 36)**	TX	Varies depending on fresh water, transport, and disposal costs
Storage pits and tanks best management practices **(Page 37)**	Multiple states	Varies depending on upgrades necessary

*For example, the average cost of cement evaluation is $9,000, and a single mechanical integrity test is $10,000, in combination less than 0.7% of the cost of a typical unconventional well (Bureau of Land Management, 2012).

Overall Policy Recommendations

The processes of developing and enforcing regulation are as important to the long-term safety and public acceptance of unconventional oil and gas production as the content of extant regulations. Chapter 4 discusses the needs, challenges, and successful approaches to strengthen the design and implementation of effective policy. The three elements include: engagement of key stakeholders, adaptive management, and monitoring and enforcement.

Engage key stakeholders throughout the planning process (chapter 4, page 30): A state can foster productive communication among stakeholders by serving as a mediator and organizing collaborative efforts engaging groups at various levels throughout the process. The collaborative process should include insight from industry stakeholders who have demonstrated leading practices, local government regulators, and non-governmental organizations known for their pragmatic policy positions. Involvement of industry from day one is critically important to maintain goodwill.

Integrate Adaptive Management mechanisms into policy infrastructure (chapter 4, page 32): Mechanisms for responding to new research and data and revising policies in light of changing practices in a timely and appropriate manner, is critical in an evolving landscape of unconventional energy development (Rahm & Riha, 2014). Regulations should be adaptable in order to accommodate new scientific evidence. For instance, a recent study identified significant methane emissions from shale wells during drilling, which was not previously recognized as a major methane contributor (Caulton et al., 2014), indicating that regulations to reduce those emissions may be needed.

Ensure states have the authority, means and capacity to monitor and enforce regulatory requirements (chapter 4, page 36): States need to allocate sufficient funding to responsibly enforce and monitor laws and regulations. For regulations to be effective, states need to fund planners and scientists to conduct the necessary research before oil and gas development begins in order to obtain baseline data to measure/monitor future changes and to assess the connection, if any, between industry actions and environmental impacts (Schumacher & Morrissey, 2013). Successful regulatory regimes emphasize continual data collection to constantly monitor the risks and impacts of shale gas development before activity even begins (Rahm & Riha, 2014).

METHODOLOGY

A group of Master in Public Affairs students at the Woodrow Wilson School of Public and International Affairs (WWS), and Ph.D. candidates from the WWS program in Science, Technology, and Environmental Policy and the Departments of Mechanical and Aerospace Engineering and Civil and Environmental Engineering at Princeton University collaborated to research and write this report. Princeton University atmospheric scientist Professor Denise Mauzerall facilitated the project as part of the annual graduate policy workshop program that enables students to address critical policy problems for real clients. This particular workshop arose out of a client's desire to develop a series of state policy recommendations to reduce gaseous emissions and water impacts from unconventional oil and gas development and distribution.

To select the particular sources of impacts and the leading technologies, practices, and policies that would be evaluated in the report, the group conducted an extensive literature review and interviewed over 45 experts and stakeholders including: public officials and staff from local, state, and federal government agencies; oil and gas operators; industry support service providers; staff at advocacy groups including environmental organizations and energy sector trade groups; journalists; and economists, scientists, and other scholars. As part of this research, team members traveled to **Colorado**, **Texas**, **Pennsylvania**, **Maryland**, and Washington, DC.

Due to the political sensitivity of this issue, we agreed to not attribute interviewees' statements directly to them. This encouraged open dialogue with a wide range of stakeholders and added valuable insight to our report. The views expressed here are the views of the authors and do not represent the views of Princeton University or necessarily a consensus among those consulted in preparing this report. None of the individuals or groups consulted in preparation for this report should be associated with the recommendations we have reached and the authors take full responsibility for any errors of fact.

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TABLE OF ABBREVIATIONS

API	American Petroleum Institute
AQCC	Air Quality Control Commission
BLM	Bureau of Land Management
BTEX	Benzene, Toluene, Ethylbenzene, and Xylene
CAA	Clean Air Act
CO_2	Carbon Dioxide
COGCC	Colorado Oil and Gas Conservation Commission
CSSD	Center for Sustainable Shale Development
CWT	Centralized Waste Treatment Facility
DBP	Disinfection Byproducts
EPA	Environmental Protection Agency
GAO	Government Accountability Office
GWPC	Groundwater Protection Council
IOGCC	Interstate Oil and Gas Compact Commission
LAUF	Lost and Unaccounted For
LDC	Local Distribution Company
LGD	Local Governmental Designee
LDAR	Leak Detection and Repair Program
NAAQs	National Ambient Air Quality Standards
NESHAPS	National Emissions Standards for Hazardous Air Pollutants
NMVOC	Non-Methane Volatile Organic Compounds
NORM	Naturally Occurring Radioactive Material
NO_x	Nitrogen Oxides (NO_x = Nitric Oxide (NO) + Nitrogen Dioxide (NO_2))
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
O&G	Oil and Gas
OGI	Optical Gas Imaging
PADEP	Pennsylvania Department of the Environment
POTW	Publicly Owned Treatment Works
REC	Reduced Emissions Completion, or Green Completion
STRONGER	State Review of Oil & Natural Gas Environmental Regulations
SIPs	State Implementation Plans
TDS	Total Dissolved Solids
TENORM	Technologically Enhanced Naturally Occurring Radioactive Material
UIC	Underground Injection Control
VOC	Volatile Organic Compounds
VRU	Vapor Recovery Unit

CHAPTER 1: BACKGROUND ON UNCONVENTIONAL OIL AND GAS DEVELOPMENT

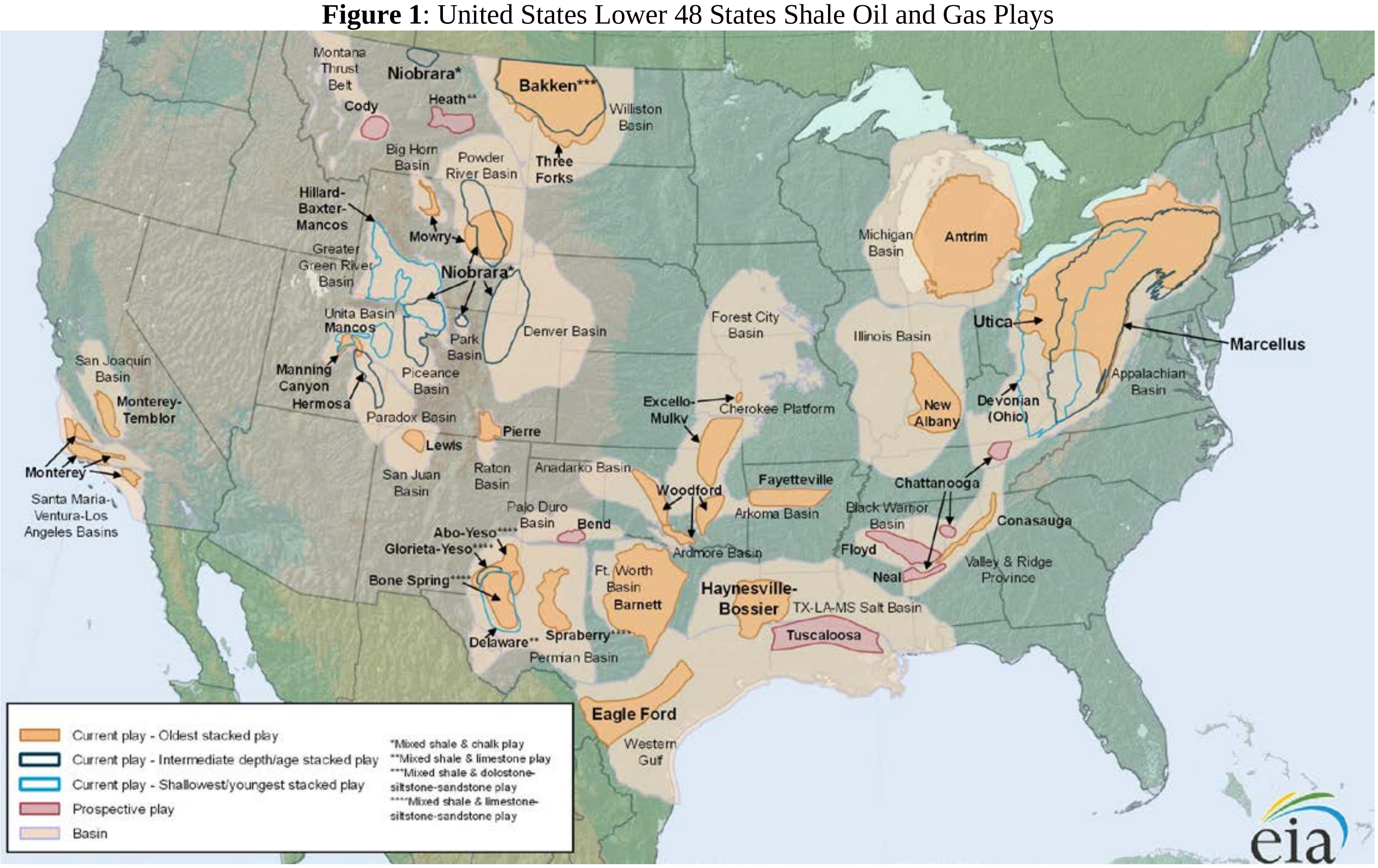
Benefits and Risks of Unconventional Oil and Gas

Unconventional oil and gas production, primarily from tight oil formations and shale gas formations, has, over the past decade, transformed the United States into the world's largest natural gas producer as well as the fastest growing oil producer (Ratner & Tiemann, 2014). Unconventional development has occurred in numerous states across the country, shown in **Figure 1** below. The Department of Energy estimates that natural gas production in the United States will grow by 56 percent between 2014 and 2040. Unconventional gas production from shale deposits will be responsible for three quarters of this growth. Oil production from unconventional sources is projected to account for over 50% of total US oil production by 2020 (Energy Information Administration, 2014a).

Natural gas could shift US electricity production towards lower carbon intensity sources. Importantly, increases in natural gas production, distribution and consumption have significant implications for greenhouse gas emissions and attendant climate change concerns. When combusted, natural gas, per unit of energy, produces less carbon dioxide than coal (Shindell et al., 2012), leading researchers and officials to herald increases in natural gas production as a viable, environmentally beneficial energy alternative to coal (Alvarez et al., 2012). Separately, the fact that power plants burning natural gas can be quickly cycled on and off make them a valuable complement to intermittent renewable energy sources. Together, these characteristics suggest natural gas has a role to play both in reducing emissions in the near term and in supporting the development of a more sustainable energy future.

The issue is complicated by methane emitted during natural gas development and distribution, and associated gas emitted during unconventional oil development. Methane has a global warming potential approximately 34 times greater than carbon dioxide, on a mass basis, over 100 years (Stocker et al., 2013). Thus, the climate benefits of natural gas depend on the amount of methane leaked into

Figure 1: United States Lower 48 States Shale Oil and Gas Plays



(Source: http://www.eia.gov)

the atmosphere. If methane leakage from unconventional energy development and distribution is significant, the climate benefits of natural gas will be attenuated, if not eliminated entirely (Tollefson, 2013). Despite the increasing competitiveness of renewable energy sources, low natural gas prices may also undercut the nascent renewable energy market, further weakening natural gas' climate benefits by entrenching fossil fuels in the longer term energy future (McJeon et al., 2014). Together, these factors underscore the importance of carefully managing natural gas resources and their development. In addition, the use of hydraulic fracturing requires a significant amount of water mixed with chemicals and can potentially contaminate both ground and surface water supplies throughout the process.

Recommendations to Inform Effective State Policy

The rapidly evolving landscape of unconventional energy development brings new opportunities and challenges to states trying to capitalize on the benefits, while carefully assessing and managing the risks to public health, the environment, and local economies. A variety of federal agencies have authority over aspects of the unconventional energy sector, yet federal regulations simply set minimum requirements states must enforce. States have authority to permit drilling wells and may create additional rules for the sector as they see fit, provided state regulations meet applicable federal regulations' minimum requirements (Department of Energy, 2014b, p. 18). However, **unconventional oil and gas development is exempt from multiple major federal environmental laws** including the Safe Drinking Water Act; Resource Conservation and Recovery Act; Emergency Planning and Community Right-To-Know Act; Clean Water Act; Clean Air Act; Comprehensive Environmental Response, Compensation, and Liability Act; and National Environmental Policy Act (Kosnik, 2007). **These exemptions give states leeway to create individualized regulations for unconventional oil and gas** (Brady, 2012).

Chapters 2 and 3 describe the risks unconventional oil and gas present in terms of gaseous emissions (chapter 2) and water scarcity and contamination (chapter 3), review the technical approaches to addressing these risks, and outline how state-level policy can encourage responsible development of the industry. Chapter 4 lays out specific recommendations for state policy makers to: (1) engage key stakeholders, (2) incorporate an adaptive management framework to continually improve state regulations as technology and research evolves, and (3) increase effectiveness of monitoring and enforcement.

Overview of Unconventional Oil and Gas Development and Distribution Process

Unconventional energy production refers to the extraction of oil and gas from low-permeability rock formations. Technical advances, including the combination of horizontal well drilling and high volume, water-based hydraulic fracturing, have enabled companies to extract previously unobtainable oil and gas from these formations. **Figure 2** depicts the stages within the unconventional oil and gas system, from production at the well through distribution to business and residential end users.

Drilling and fracturing

Wells are drilled from the surface to the target geological formation, typically at a depth of 5,000 to 12,000 feet, and then continue horizontally within the target formation for 3,000 to 7,000 feet. After the well is drilled, it is 'completed' by performing hydraulic fracturing. To the wider public, hydraulic fracturing, or 'fracking,' has become synonymous with the entire process of extracting oil and gas from unconventional reservoirs, when it is just one component of a broader process. Hydraulic fracturing involves perforation of the horizontal section of the well casing and pumping of large volumes (2-7 million gallons per well per treatment) of hydraulic fracturing fluid into the well at very high pressure to induce fractures in the formation (Department of Energy, 2014b; Vidic et al., 2013). Predominantly water, the fluid also contains proppant (grains that lodge in fractures to hold them open) and chemicals added to enhance its fracturing properties.

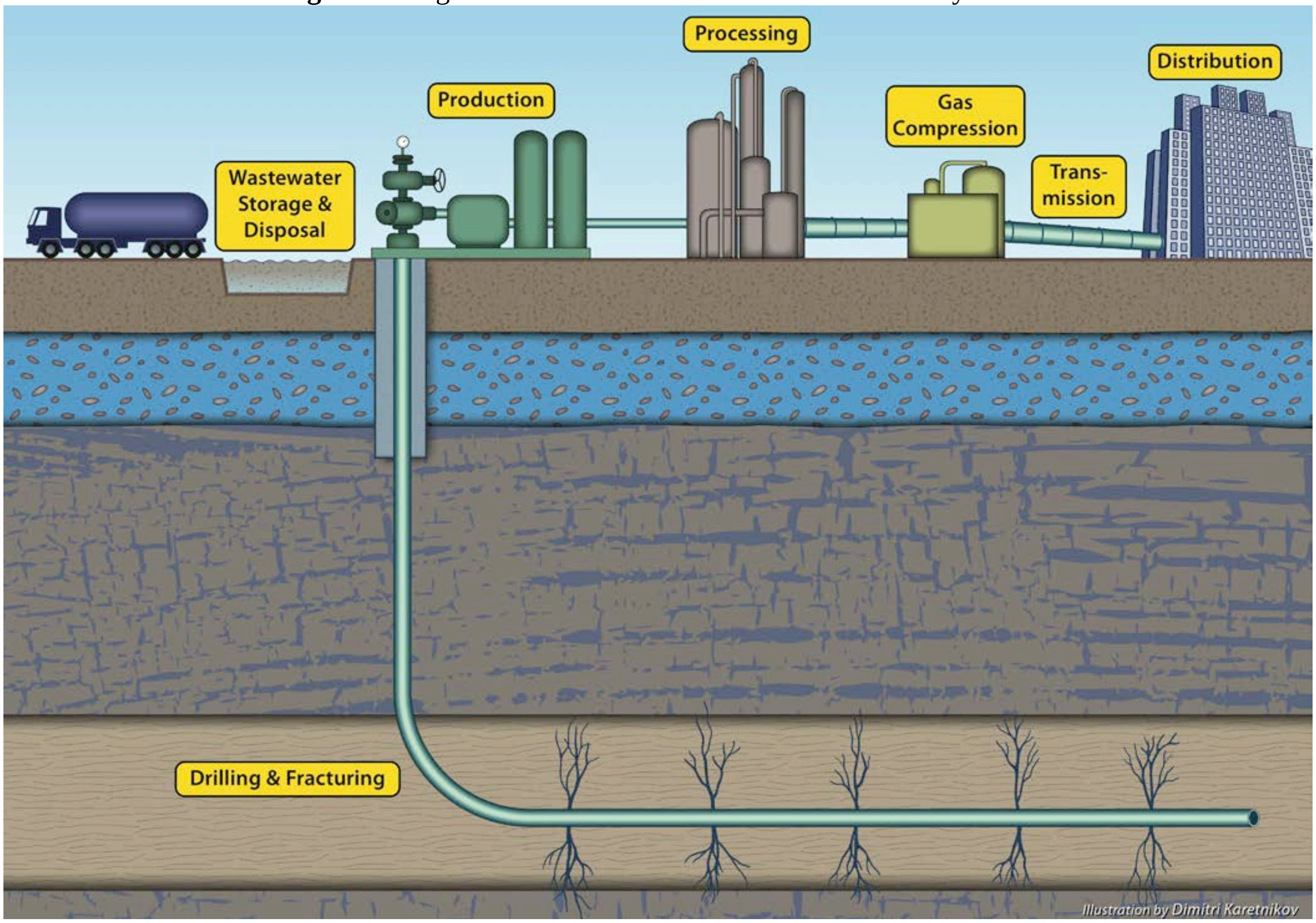
Wastewater storage and disposal

Following hydraulic fracturing, the fracturing fluid flows back out of the well. This 'flowback' water contains a mixture of the hydraulic fracturing fluids and brine from the target formation (Vidic et al., 2013). Over a period of several days to several weeks, the rate of water flow decreases and the oil and/or gas flow initiates and progressively increases. Only 10 to 50% of the injected volume of fluid returns, with the average near 30% (Department of Energy, 2011). The remaining water likely remains in the target formation, although its exact fate remains unknown (Vidic et al., 2013).

Production, processing, and gas compression

Production refers to the process of taking the raw fluids from the reservoir and processing them into a form suitable for use by downstream users. The reservoir fluid typically consists of water, crude oil (liquid hydrocarbons), and natural gas. The goal of this stage is to separate the water, oil, and gas, and process each component to meet a

Figure 2: Stages within the Unconventional Oil and Gas System*



*Note: Not drawn to scale.

pre-determined standard. The well site contains limited equipment to achieve this basic separation. While the oil and co-produced water are typically stored in separate tanks onsite for collection by tankers, the gas is either exported to a central processing facility, or in the case of oil wells, may be flared or vented at the pad if the required infrastructure does not exist for gas export to market.

Later in well life, gas compression may be required to boost the gas into gathering lines to the central processing facility. At the central processing facility, gas is further treated before compressing it into an export transmission pipeline. Between each processing plant and transmission pipeline, a sales-gas metering skid measures how much gas the operator puts into the transmission pipeline.

Gas compression, transmission, and distribution

The natural gas transmission system transports gas from processing facilities to local distribution companies, which deliver gas to end-users. Typical transmission pipelines provides capacity for more than one facility and operator. Compressor stations are built every 50-60 miles and serve to boost pipeline pressure and maintain the volume of transported gas. While production processes for conventional and unconventional gas differ considerably, both feed into the same natural gas distribution system. This means that the concerns regarding air emissions during transmission, storage, and distribution apply to conventional as well as unconventional gas development.

Well plugging and abandonment

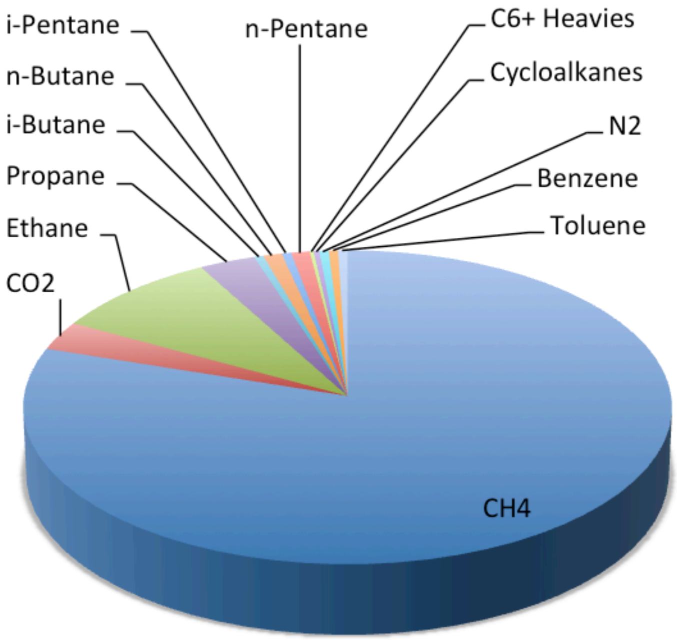
The production period of a well can last on the order of decades, during which the flow rate of hydrocarbons from the well gradually declines. The well may be hydraulically fractured multiple times during its lifetime to maximize oil and gas extraction. Regulations require wells to be plugged with cement or other suitable material at the end of their life before they are abandoned to prevent the flow of fluids within and out of the abandoned well.

CHAPTER 2: RISKS TO AIR QUALITY AND LEADING MITIGATION OPTIONS

Environmental and Health Risks from Air Emissions

Unconventional oil and gas development is a significant source of air pollution. Natural gas, when released into the atmosphere, has a range of air quality and associated adverse impacts on human health and welfare. These impacts vary from local and regional effects to global impacts, depending on the specific component of the gas in question. Expanding unconventional oil and gas extraction, and shale development in particular, is found to contribute to increased air pollution, which is associated with higher morbidity and mortality risks (PSE Health Energy, 2014).

Figure 3: Typical Composition of Natural Gas



Source: Adapted from Environmental Defense Fund, 2014b

Natural gas consists primarily of methane (70-90%), some ethane, C3+ hydrocarbons known as volatile organic compounds (VOCs) (0-20%), and small quantities of other inert (0-8% CO_2) and toxic (0-5% hydrogen sulfide) components. **Figure 3** shows the composition of natural gas in more detail.

Historically, VOCs have been some of the most tightly controlled gaseous emissions due to their significant impacts on local air quality and human health. VOCs, some of which are carcinogenic, can directly cause eye irritation, respiratory irritation, and decrease visibility due to blue-brown haze (Pidwirny, 2014). Additionally, VOCs react with ambient nitrogen oxides (NOx) in the presence of sunlight to form surface ozone (O_3) and photochemical smog, which significantly increases the risk of death from respiratory causes (Jerrett et al., 2009), and reduces crop yields and forest growth (Fahey and Hegglin, 2010).

More recently, there has been an increased focus on methane itself as a pollutant. Because methane's breakdown half-life is approximately 12 years (Stocker et al., 2013), emitted methane is transported around the world and contributes to increases in global background concentrations of ozone, a component of photochemical smog, with adverse effects on human health and welfare (Fiore et al., 2008; West et al., 2006).

Methane is the second most important greenhouse gas. Depending on the time horizon used to calculate relative impacts, it is 34 (over 100 years) to 86 (over 20 years) times more efficient at trapping energy within the troposphere than CO_2 (Stocker et al., 2013). While natural gas produces less CO_2 per unit of energy when burned than other fossil fuels (coal for generating electricity or petroleum products for vehicles), even a relatively small leak of methane (3.2% for gas used in electricity production, or 1% inclusive of transport) during production and transmission may result in a larger climate impact than other fossil fuels (Alvarez et al., 2012).

Additionally, methane is a valuable commodity, and leakage equates to an economic loss. Methane capture can increase the availability of natural gas, which may reduce CO_2 and air pollutants emissions from burning other fossil fuels (West et al., 2005). Based on health, environmental and economic factors, it is imperative to decrease methane emissions.

Sources and Quantification of Air Emissions from Unconventional Oil & Gas

Oil and natural gas production is responsible for over 11% of total anthropogenic VOC emissions in the US (Lattanzio, 2013). The natural gas and petroleum system in its totality is the largest source of anthropogenic methane emissions in the US, accounting for approximately 29% of total methane emissions (EPA, 2014a). Natural gas leakage can occur throughout the entire natural gas development, production and transmission cycle, from well completions, through to the production, processing, transmission, and distribution of the gas. Wells that produce oil affect air quality primarily through the venting or leakage of associated gases during production, and from gaseous byproducts of oil processing and combustion. Indeed, oil wells may produce higher gaseous emissions than gas wells, as they may not be connected into gas gathering infrastructure, and emissions are likely to have a higher proportion of VOCs (high carbon molecules) by definition. Thus each stage and type of process presents a unique set of challenges for reducing emissions.

Critically, most post-extraction processing, transmission, and distribution use essentially the same processes and equipment for conventionally and unconventionally derived hydrocarbons. Therefore, emission sources and quantities at these stages are similar across methods of extraction. The well completion processes used and the scale of well-site equipment differ between conventional oil and gas. Typically, unconventional oil and gas production has a larger environmental impact than conventional oil and gas development because unconventional resources are more broadly distributed and are trapped in lower permeability rocks that impede their flow (International Energy Agency, 2012).

Researchers have put considerable effort into quantifying upstream greenhouse gas emissions from unconventional gas, though significant uncertainty remains due to the vast number of unconventional gas wells and the huge variation in gas composition, equipment and operating practices across basins and wells. A large number of studies have attempted to quantify the lifecycle greenhouse gas emissions from these systems. Inherently, there is a significant range in these estimates due to natural variability in leakage rates across different wells and equipment, which is compounded by uncertainties in estimates of specific procedures and the pervasiveness of given pieces of equipment. Additionally, only a small number of these emission estimations are based on recent field measurement, with most studies using outdated EPA emission factors that were obtained two decades ago (Bradbury et al., 2013). Furthermore, researchers have questioned data quality on methane emissions, as many datasets are often constructed from voluntary industry submissions (Howarth et al., 2011). **Table 1** shows a comparison of emissions from conventional and unconventional sources and illustrates the large variability in the estimates of leakage from the different stages of unconventional and conventional oil and natural gas development.

In spite of the challenges of precisely quantifying emissions from each source, there is a relatively clear understanding of the major contributors to methane leakage. **Figures A1 through A3** in the appendix show the major sources of greenhouse gas emissions from the US natural gas system. Production, processing, transmission and distribution, all four stages, have significant methane emissions, accounting for 32%, 14%, 33% and 20% of total methane emissions from natural gas industry, respectively. Given uncertainties regarding the scale of methane emissions from various sources, regulations should be adaptable so they can accommodate new scientific evidence. For instance, a recent study identified significant methane emissions from shale wells during drilling, which was not previously recognized as a major methane contributor (Caulton et al., 2014). Continual efforts via both top-down and bottom-up studies are needed to better quantify emission sources, including from operators themselves to verify any assertions about the extent of emissions.

Across all of the processes and equipment responsible for gas leakage, a small number of sources are responsible for the vast majority of emissions. Several recent studies (e.g. Allen et al., 2013; The Prasino Group, 2013) have utilized direct measurement of gas leakage from oil and natural gas production to document this “fat-tail” problem. For example, 80% of emissions from pneumatic actuators come from only 27% of the sources (Allen et al., 2013). These major sources of leakage are spread across all types of actuators, including types designated as low-bleed. In many cases, such as low bleed pneumatic actuators or liquids unloading with plunger lift systems, emissions can be extremely high (Allen et al., 2013). This can be related to poor maintenance, harsh service or poor procedures and management of processes. Many of these leakage points are unknowable without measurement and verification. This demonstrates a critical point: there need to be controls and procedures in place across all equipment and processes to identify and control these fat-tail emissions, regardless of whether the process or equipment is designated as low emission, otherwise the regime for controlling emissions may miss a class of equipment or procedure with an oversized contribution to emissions.

Pre-production: Well completion

Well completions are the largest contributor to greenhouse gas emissions during the pre-production stage. After wells have been hydraulically fractured, the well fluid is flowed back to the surface, typically into temporary equipment, to clean the well and fluid stream, before the fluid is directed into permanent production equipment. Relative to conventional wells, the prolonged flowback period in unconventional wells contributes to substantially higher emissions from venting and flaring (Bradbury et al., 2013). This process can take from a few days to two weeks. In some cases, the flowback fluids run into temporary open-top tanks for the full duration of flowback, in which case all gases are vented to the atmosphere. Conversely, flow can be immediately directed into a separator with all gases sent to export or flare. In practice, most flowbacks fall somewhere between these two scenarios (Allen, et al., 2013). Therefore, there is large variation in emissions from flowback, dependent on the well and clean up methods used. A flowback in which gas is directed to export once there is any significant gas volume is called a "reduced emission completion" (REC), or "green completion".

Production: Workover

Over the life of an unconventional well, production will decline. To re-stimulate production, the well can be re-fractured, which is known as a well workover. Like a well completion, the well must undergo flowback, which will result in varying degrees of emissions depending on the flowback method used and well characteristics.

Production: Liquids unloading

As wells age, reservoir pressure and fluid flow rates decline. In some cases the gas flow rate and reservoir pressure is insufficient to drive reservoir liquids completely from the well. This results in liquids accumulating in the well, which may increase the backpressure on the formation to the point the well stops flowing, an event known as liquids loading. Operators use a variety of methods to unload liquids from the well.

Venting, or blowing down a well, is a common method to clear wells with liquids loading. This involves shutting in a well to increase the bottom hole pressure, and then venting the well to the atmosphere to reduce the backpressure. The built up liquid and gases then flow up from the well. Once the liquids are removed the well is returned to service. This process can cause significant vented emissions (Bradbury et al., 2013).

Some studies overlook liquids unloading as a potential source of emissions from unconventional oil and gas production, including several studies by the Environmental Protection Agency (EPA) that suggest liquids unloading is only necessary for onshore conventional wells (2011a, 2012). However, a survey of the industry found liquids unloading is a common practice for both conventional and unconventional wells (Bradbury et al., 2013).

Production: Fugitive & vented emissions from equipment

Emissions from equipment can be separated into two categories, and the methods for effectively dealing with each differ. Fugitive emissions are unintended leakages from process equipment, such as leaks from a valve body. These emissions can be minimized through the use of leak detection and repair and regular maintenance programs. Conversely, vented emissions originate from equipment or processes that are designed to have some leakage to the atmosphere during their operation, such as venting during operation of gas pressure driven valves or pumps. Emissions from these sources can be minimized by using low- or no-emission technologies, capturing the emissions and routing them back to the process or a combustion completion device, or by modifying operating practices.

Table 1: Lifecycle Greenhouse Gas Emissions from Conventional and Shale Gas Production
(units are grams of carbon dioxide equivalent per mega joule produced, with range of estimates reviewed in parentheses)

Major Sources	Conventional gas	Shale gas
Emissions During Well Completion	0.18 (0-0.4)	2.0 (0.1-8.6)
Routine Venting and Equipment Leaks at Well Site	2.9 (1.1-5.0)	2.9 (1.1-5.0)
Emissions During Liquid Unloading	2.9 (0.6-6.6)	0*
Emissions During Workovers	0	2.5 (0-4.8)
Emissions During Gas Processing	5.2 (1.2-15.3)	5.2 (1.2-15.3)
Emissions During Transport, Storage and Distribution	2.2 (0.1-7.4)	2.2 (0.1-7.4)
Total	13.4 (3-34.7)	14.8 (2.5-41.1)

*Note: Estimates presented assumed shale gas wells do not require liquids unloading. An industry survey found it is common practice in shale plays (Bradbury, 2013).

Source: Jiang et al., 2011; Howarth et al., 2011; Department of Energy, 2011; Stephenson et al., 2011; Burnham et al., 2011; Hultman et al., 2011; Weber and Clavin, 2012

All processing equipment and piping, whether at the well site, processing plant, compressor sites or gathering and transmission lines, have the potential for fugitive emissions. Leakage points include valve bodies and stems, pressure relief valves, flanges, open-ended lines, sampling and instrument connection points, and pneumatic systems. Fugitive emissions make up 56% of emissions from the natural gas system including, and as **Figure A3** shows, 85% of emissions during processing (EPA, 2014a).

A range of equipment vents gas as part of its normal operation. Valves and pumps can operate pneumatically from the pressured process gas, and during operation this gas is released to the atmosphere. Oil seals (wet seals) and dry gas seals on centrifugal compressors have gaseous emissions as part of their operations, and the packing on reciprocating compressors leaks a small amount of gas into the compressor housing, which is then typically vented to the atmosphere (EPA, 2014c). If not connected to flare or a vapor recovery unit, oil tanks vent gases (including a high level of VOCs due to the liquid nature of the contents) to the atmosphere as the tank fills, or as the tank naturally heats and cools during the diurnal cycle. Some of the highest vented emissions come from compressor seals, pneumatic devices and liquids unloading, together representing a significant proportion of methane and VOC emissions in the natural gas sector (EPA, 2014a).

Transport, storage, and distribution

Importantly, estimates of natural gas leakage from natural gas transport, storage and distribution are the same for conventional and unconventional gas wells (Howarth et al., 2011). While production processes for conventional and unconventional gas differ considerably, both methods feed into the established natural gas transmission and distribution systems. As such, concerns over methane leakage from the distribution system lie not in the unconventional oil and gas processes themselves, but rather in the way unconventional production stands to significantly increase natural gas usage nationally in the coming decades.

Policy Landscape

The federal Clean Air Act (CAA) regulates "air emissions from area, stationary and mobile sources". The CAA gives the US EPA authorization to enact regulations and policies that protect both public health and the environment. In 1977 and 1990, the CAA was amended to address problems like "acid rain, ground-level ozone, stratospheric ozone depletion, and air toxins," (Clean Air Act, 1970).

The EPA also sets new source performance standards (NSPS) for industrial categories that "cause, or significantly contribute to, air pollution that may endanger public health or welfare." This is in conjunction with the National Emissions Standards for Hazardous Air Pollutants (NESHAPS) that "regulate specific hazardous air pollutants," (Clean Air Act, 1970). The EPA is required to review these standards at least every eight years.

Under NESHAPs, small sources of air pollution that are under common control and grouped together in close proximity to perform similar functions are required to be considered as one source of emissions. If the aggregate emissions of these small sources meet the thresholds for major sources, they must comply with NESHAPs. This aggregation is meant to shield the public from smaller sources that individually seem harmless but cumulatively account for large volumes of toxic substances released into the air. However, **the CAA completely exempts oil and gas exploration and production activities from this aggregation requirement, leaving combined emissions unchecked** (EarthWorks, n.d.; Kosnik, 2007).

EPA rules toward meeting the CAA

The primary federal mechanism for controlling leakage and venting of natural gas in oil and gas development is through restrictions on VOC emissions under the NSPS, in light of the direct environmental and health impacts of VOC emissions. Methane emissions have generally only been controlled as a co-benefit of controls on VOCs, not through any regulations explicitly directed at their control (Colorado Dept. of Public Health and Environment, 2014).

The NSPS for VOCs were extended in 2012, and included the first federal air standards for hydraulically fractured natural gas wells along with regulations covering several other sources of pollution in the oil and gas industry that were not previously regulated at the federal level (EPA, 2014b). The final rules are estimated to provide a 95% reduction in VOCs emitted from over 11,000 new hydraulically fractured *gas wells* per year; however this does not affect existing wells or unconventional oil wells. The reduction primarily stems from increased use of RECs (green completions) (Department of Energy, 2014a).

The estimated revenues from selling the gas that currently goes to waste are expected to offset the costs of compliance, while significantly reducing pollution. EPA's analysis of the rules shows a countrywide cost savings of \$11 - \$19 million when the rules are fully implemented in 2015 at an estimated gas price of \$10.93/ft^3 (Nolon, 2013).

National Ambient Air Quality Standards (NQAAS)

All states are required to meet the National Ambient Air Quality Standards (NQAAS), which include a standard for allowable surface ozone concentrations. Importantly, states that have regions that fall outside of this standard, known as nonattainment regions, must develop a plan to address the non-compliance through their State Implementation Plans (SIPs). As seen from the current 8-Hour O_3 nonattainment map (0.075 ppm) (**Figure 4**), many shale plays have already fallen into the nonattainment regions.

Figure 5 shows the potential future 8-Hour O_3 nonattainment map under EPA's newly proposed O_3 standards released in November 2014, showing a clear overlap of shale production and O_3 nonattainment regions.

If the EPA adopts tighter restrictions regarding surface ozone levels, most of the states where unconventional oil and gas is present, including **Colorado**, **Utah**, **Texas** and **Pennsylvania**, will be required to submit revised State Implementation Plans (SIPs) to detail how they will return to compliance in surface ozone concentrations. As the oil and gas industry is a large source of O_3 precursor emissions (both VOCs and methane), limiting emissions from the oil & gas sector may become necessary for these states in the near future. **States that pre-emptively address the tightening of the NQAAS address the tightening of the NQAAS requirements through more strict air regulations, including direct methane control, may find such an approach beneficial to "get ahead of the curve"** and avoid more drastic and less flexible requirements that would likely become part of an SIP.

Case Study - Enacting Good Regulation in Colorado

Many examples exist of effective state regulation of the unconventional oil and gas sector across the US. **Alabama, Alaska, Arkansas, California, Colorado, Indiana, Maryland, New York, New Mexico, North Dakota, Ohio, Pennsylvania and Wyoming** are several of the states who have revised or are revising their O&G rules to address unconventional oil and gas development. **Colorado** is an example of a state that has learned from other states as well as developing its own leading practices and sharing that knowledge with others. This case study presents some of the key events and developments in **Colorado** that have allowed the state to become a front-runner in many areas of oil and gas regulation.

Development of Colorado state regulations

There are two main state regulatory bodies for unconventional oil and gas development in **Colorado**, the Air Quality Control Commission (AQCC), under the **Colorado** Department of Public Health and Environment, and the **Colorado** Oil and Gas Conservation Commission (COGCC), under the Department of Natural Resources.

The **Colorado** General Assembly created the COGCC, often referred to as "the Commission," to "foster the responsible development of **Colorado**'s oil and gas natural resources" (EarthWorks, 2012). Leading up to 2007, with impacts from rapidly expanding unconventional oil and gas development being felt across the state, policymakers decided to strengthen regulation in order to better protect public health, communities, and the environment.

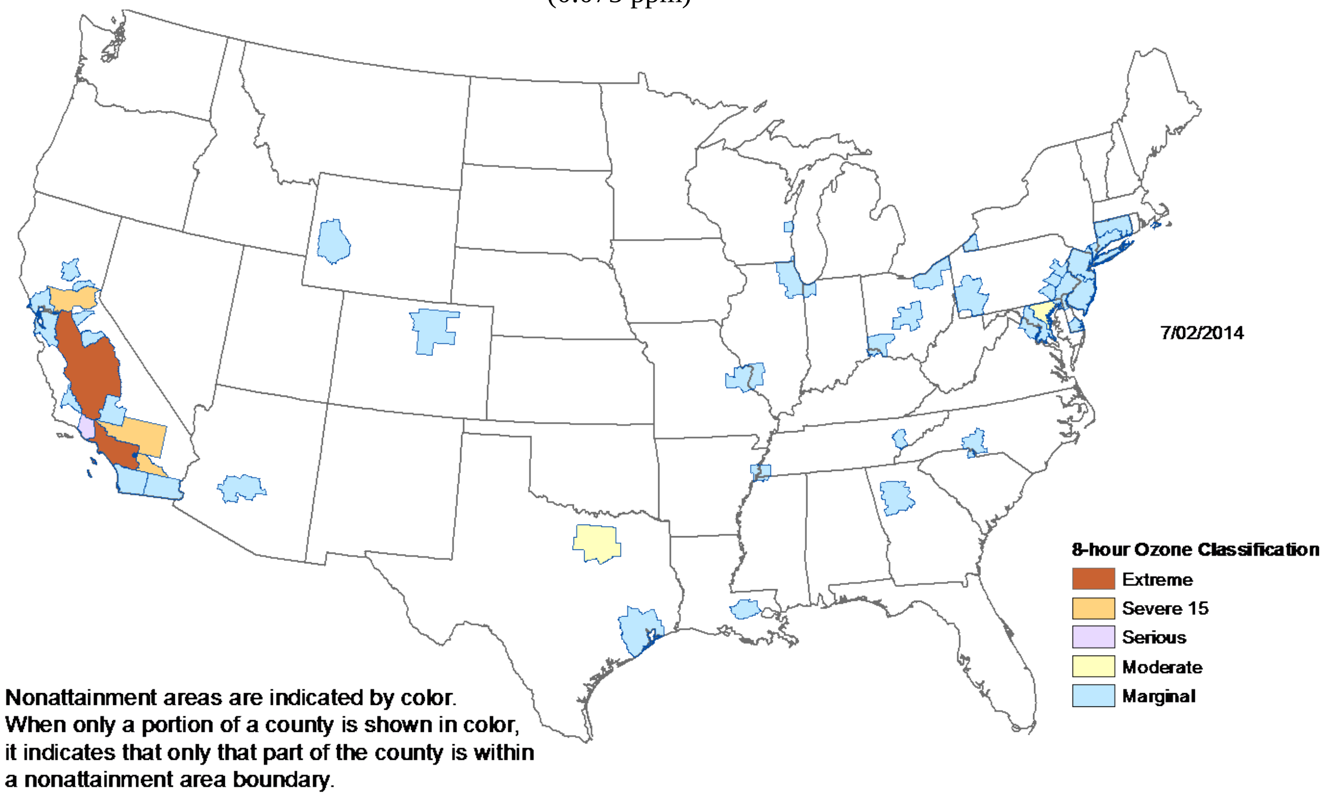
Building on legislative changes from 1994, the **Colorado** General Assembly further extended the Commission's regulatory powers in 2007 to "foster the responsible, balanced development of **Colorado**'s oil and gas resources consistent with the protection of public health, safety, and welfare, including protection of the environment and wildlife resources," (EarthWorks, 2012). In coordination with a significant change in the Commission's make-up, moving away from an oil and gas industry dominated group to a more broadly inclusive nine-member group, these legislative changes have driven a significant era of policy- and rule-making in the state of **Colorado**.

Since 2007 there have been four main rounds of rule making at the COGCC and AQCC:

- 2008: Extensive COGCC rulemaking including changes related to air quality: requirements for RECs, low-bleed/no-bleed actuators, and tank VOC emission controls;
- 2011: COGCC Chemical disclosure of fluids used for hydraulic fracturing and well location rules;
- 2012: COGCC rules on setbacks of O&G drilling from dwellings and other buildings, and water monitoring rules;
- 2014: Significant AQCC controls on emissions of hydrocarbon gases, including extensive LDAR programs, strengthening and extending 2008 rules on actuators and tank emissions, as well as those on compressor seal replacement.

During these rule-making periods, **Colorado** was able to model rules on those of other states, such as **Wyoming** (for RECs and LDAR) and **Texas** (for chemical disclosure). Other state regulatory bodies, such as in **Ohio**, have emulated some of **Colorado**'s rules as leading practices in their own jurisdictions.

Figure 4: Current 8-Hour Ozone Nonattainment Map under Existing NAAQs for Ground-Level Ozone (0.075 ppm)



Source: http://www.epa.gov/glo

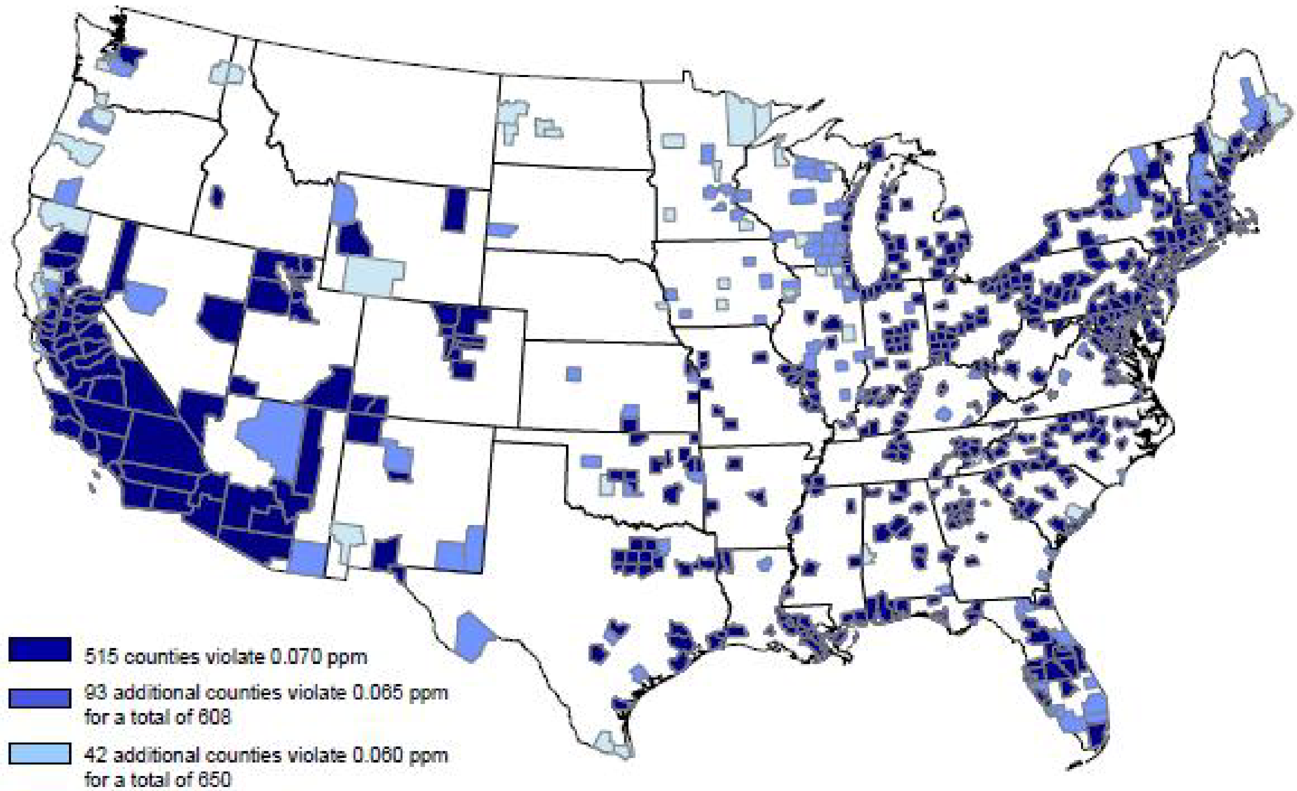
Regulatory process

Colorado's most recent changes to air emission regulations provide a useful model not only in their substance, but also in the process that led to their adoption. In 2013, a significant community groundswell began pushing for tighter regulation of oil and gas industry pollution, particularly related to increased air pollution and the expanding oil and gas footprint. The most vocal groups represented a departure from typical environmental groups, maintaining a stronger focus on public health and community issues, rather than less tangible environmental impacts. Major parties included a grassroots community group known as Colorado Moms Know Best, the American Lung Association, and National Jewish Health, which mobilized broad community support. Late in 2013, both government and industry leaders in **Colorado** expressed the aspiration of achieving zero methane emissions from oil and gas development (Ogburn, 2014).

In 2013, the AQCC developed draft rules that were then handed to a working group consisting of the three largest producers in **Colorado** (Anadarko, Encana, Noble) and the Environmental Defense Fund (EDF). This working group was tasked by the Governor to reach a consensus on the final rules (Ogburn, 2014). The Governor's office and the EDF played a critical role in brokering deals with industry.

The result was the 2014 AQCC rule titled "Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions," which imposed first-of-its-kind stringent hydrocarbon control requirements on oil and gas production, including a 'no venting' standard for most storage tanks, an increase in combustion device efficiency and comprehensive periodic monitoring requirements (Greenslade, 2014). These regulations represented a significant departure from previous rules at both state and federal levels, which typically only controlled for emissions of non-methane and ethane VOCs. In contrast, the new AQCC rules did not focus on controlling major sources of VOCs only, but expanded regulation to directly control hydrocarbon gases. Such a change allows for a broader application of controls, applying to a much broader subset of equipment. Lessons from **Colorado**'s experience for other states are summarized in **Box 1**.

Figure 5: Potential 8-Hour Ozone Nonattainment Map under Proposed NAAQs for Ground-Level Ozone (0.060-0.070 ppm)



Source: http://www.epa.gov/glo

Leading Technologies to Reduce Emissions

Many specific technologies and practices can be implemented to significantly reduce hydrocarbon emissions from oil and natural gas production. Existing federal regulation covers many aspects of the industry, however regulation tends to be piecemeal with significant gaps and exemptions. In lieu of federal regulation, state regulation can further reduce air impacts from unconventional oil and gas by:

- Extending REC and/or no venting requirements to oil wells. They currently only apply to gas wells;
- Removing exemptions from the NSPS for specific types of equipment, for example, where low-bleed pneumatic actuators are exempted from LDAR programs. For example, implement a comprehensive, broad-based LDAR program that covers all equipment from the wellpad through to the transmission lines;
- Phasing-in stricter requirements for high-emission existing equipment rather than solely applying standards to new or reconstructed facilities;
- Extending requirements, such as those for LDAR and compressor seal replacement, into the transmission sector; and/or
- Making limits more stringent, for example by reducing the allowable VOC emissions from storage tanks.

As described above, some states have effective regulation that extends beyond federal rules and reduces the environmental impacts of oil and natural gas development **– Colorado, Wyoming, Illinois, and Maryland** being examples. Learning from and sharing with other states is also common sense, and often regulation can be adapted from other states, such as in the development of chemical disclosure rules, started by **Wyoming** and **Arkansas**, and followed by **Texas** and **Colorado**. Some technological options for addressing emissions are presented below, and many of these have proven cost effective.

Leak detection and repair programs

Unintended fugitive emissions from equipment can be effectively controlled using LDAR (Carbon Limits, 2014). LDAR programs require periodic inspection of equipment and facilities with an optical gas imaging (OGI) camera or other detection device. Such devices can detect small rates of leakage of natural gas, and in the case of an OGI camera, the leak may be easily visualized at a distance and

Box 1: Key lessons from **Colorado** that can be applied to other states.

1) State Governors and legislatures should engage stakeholders from the beginning in planning regulations. It is of vital importance to begin dialogue with industry from day one. The collaborative process should include insight from industry stakeholders who have demonstrated leading practices, local government regulators, and strong non-governmental organizations known for their pragmatic policy positions.
2) Establish working groups within the state that represent key stakeholders (industry, community, NGO) to assess implementations and rules.
3) As a starting point, states can control methane as a co-benefit of controlling VOC emissions. Specific EPA rules provide a well-tested starting point for stronger regulation, if the piecemeal and exemption-laden nature of the EPA rules are patched up:
   a) Specific rules, such as LDAR, should be applied uniformly across all equipment, whether in the production or processing portion of the industry. Exemptions, such as for "low-bleed" equipment should not be permitted;
   b) Specific rules, such as the installation of emissions controls on tanks, should be phased in across all equipment regardless of start-up date, not only applied to new equipment.

Expanding emission controls to hydrocarbons in general, including methane and ethane, will allow for regulation covering downstream segments that are not currently covered, but which represent a large portion of natural gas leakage, such as transmission compressors. Scheduled decreases of allowable federal ozone and hazardous air pollutant limits under the CAA may enable direct control of methane and ethane, as these chemicals have impacts on ozone pollution. In addition, many more areas will fall into ozone non-attainment under new, stricter air quality requirements.

States will have an obligation to meet the more stringent federal standards that will necessitate more controls on unconventional oil and gas. These regulations could feasibly include direct control on hydrocarbon emissions, expanding the former focus on purely VOC emissions.

4) Establish a baseline of air monitoring protocols to test for methane levels that apply across the state. This will also strengthen other measures such as:
   a) Requiring real-time air monitoring equipment around wells for methane,
   b) Requiring pipeline tracing monitoring to test for leakages, and/or
   c) Increasing fines associated with known violations

a large amount of equipment scanned in a time efficient manner. It should be noted that an OGI camera measurement is not quantitative, and provides only an indication as estimate of leakage rates, to at least 500ppm, the threshold of the EPA NSPS OOOO rules. Due to this, on detection of a leak with an OGI camera, LDAR regulations require that a repair be attempted within a fixed period of time. When properly implemented, these methods have proven to be effective (EPA, 2007; Carbon Limits, 2014).

It is crucial that LDAR programs are broad ranging and inclusive across all equipment types. In contrast, actuators that are designated as low-bleed are excluded from LDAR under current EPA regulation. However, several studies (e.g. Allen et al., 2013; Prasino Group, 2013) have shown that even low-bleed devices can have emissions far in excess of their design vent rates, and that a small number of devices are responsible for the majority of emissions.

Under current EPA regulation (40 Code of Federal Regulations § 60 and 63) several segments of the oil and gas industry are required to have an LDAR program, although requirements tend to be piecemeal and a significant amount of equipment is currently exempted from these requirements. Both **Colorado** and **Wyoming** have implemented more extensive LDAR programs using OGI cameras. **Colorado** introduced rules (5 Code of

Colorado Regulations § 1001.9) in 2014, which extend EPA regulations, requiring documented LDAR for well production facilities, natural gas compressors (not including in the transmission sector), and gas plants regardless of plant construction or modification date. Inspection frequencies are variable based on risk and potential emissions factors. **Ohio** introduced extensive LDAR requirements in 2014, requiring 3-monthly inspection of equipment. Also in 2014, **California** introduced LDAR requirements for the distribution sector.

Pneumatic valve actuators

Pneumatic valve actuators and level controls are commonly powered using gas from the process stream. The gas provides a pressure source to operate the valves, and these actuators can be a significant source of emissions as they typically bleed gas to the environment either continuously or intermittently on each valve operation. Combined with LDAR, the installation of low or no-bleed controllers can result in a significant decrease in VOC and methane emissions from pneumatic controllers.

Recent studies have found that installation of low-bleed controllers can reduce emissions by an order of magnitude (Allen et al., 2013). A requirement that operators use no-bleed (air or electricity driven) actuators wherever electricity is available removes emissions from these sources completely. Several operators are moving to solar powered valve actuators with battery backup at well sites, although not currently required under existing regulation, indicating these technologies are becoming competitive. **Colorado** has recently extended rules to require that all operators install low-bleed pneumatic devices across the whole state, and that operators must use no-bleed actuators wherever electricity is available, unless economically infeasible (5 Code of **Colorado** Regulations § 1001.9).

Pneumatic Pumps

Like pneumatic actuators, pneumatic pumps operate from pressure supplied by the gas supply. These are typically used for chemical injection and glycol dehydration systems. Exhaust gas is typically vented into the atmosphere or is sometimes captured and used for a secondary purpose. In particular, 'Kimray' glycol recirculation pumps are a high emitter; according to the EPA (2014a) they were responsible for more than 13% of the methane emissions from the natural gas production and processing sectors in 2012.

Like pneumatic actuators, these systems should move to no-bleed devices where possible, specifically electric pumps powered either from site electricity or from a local solar panel combined with a battery system. Where pressurized air (known as instrument air) is available on site, pumps can be run equally effectively on air with no emissions. Alternatively, where no site power or instrument air systems are available, exhaust could be routed to a vapor recovery unit (VRU) or flared.

There is currently little regulation in place covering pneumatic pumps, either at a state or federal level. The Environmental Defense Fund (2014a) has noted that use of solar-powered chemical injection pumps is widespread in key areas including the Eagle Ford shale in **Texas**, and that an EPA Natural Gas STAR partner has reported that replacement of pneumatic pumps with their solar powered equivalent is cost effective, with a recovery on initial investment within 5-6 years.

Pumps that vent natural gas as part of their operation should be banned where electricity or another power source for operation (for example a compressed air system) is available. Existing pneumatic pumps, particularly Kimray pumps, should be phased out entirely. This is a cost effective reduction in gas emissions, with a positive NPV for the operator (ICF, 2014). Consideration should be given to requiring operators to install solar powered pumps with battery backup where electricity is not available, unless justified economically.

Little or no state or federal regulation seems to exist requiring installation of electric instead of pneumatically driven pumps. This is one of the most cost saving methods to reduce a significant proportion of emissions.

Compressors

Compressors are used to increase pressure and maintain gas flow rates in pipelines. All compressors require seals to isolate the process gas inside the equipment from the external atmosphere, and regardless of design there will be some inherent leakage from these seals. Modern low-leakage designs and well-maintained equipment can reduce this leakage. Two main types of compressors are used in the natural gas industry: centrifugal and reciprocating. The EPA (2014a) estimated that together these compressors were responsible for emissions of over 2 million metric tons of methane across the production, processing and transmission and storage sectors in 2012 alone. This represents one of the major sources of methane leakage in the oil and gas industry.

On reciprocating compressors, rod packing separates the process gas from the compressor casing and the atmosphere. As rod packing wears, large amounts of gas can leak. Regular monitoring with rod packing replacement and maintenance is the most effective way to reduce leakage levels significantly. In addition, the gas from the casing can be routed back into the process if a vapor recovery unit exists, or the gas can be flared. If a VRU or flare is used, it is possible to reduce methane emissions by more than 95% (EPA, 2014c).

For centrifugal compressors, a seal is used to separate process gases from the environment. Compressors using an oil film seal (wet seal) typically vent gas that becomes entrained in the seal oil, which can lead to significant emissions. Connecting the oil degassing system to a VRU can control emissions from wet gas seals. This gas can either be routed back into the process or flared. Another option, typically used in new compressors rather than retrofits, is the installation of dry gas seals, which results in a lower emission seal.

Recent EPA regulations (40 Code of Federal Regulations § 60 and 63) require that rod packing be replaced every 26,000 hours of operation or every 3 calendar years. However, the natural gas transmission sector, the largest emitter of methane from compressors, is exempt from this requirement. These requirements should be extended across all compressors in the oil and natural gas industry.

Compressors vibrate significantly during service, which exacerbates fugitive emissions from associated equipment (EPA, 2014c) such as piping, tubing and flanges. An adequate LDAR program, as discussed above, should cover this equipment.

Requiring a gas capture system (to flare or back into the process) on existing centrifugal compressor wet seals can cost effectively reduce natural gas emissions, and a net positive benefit to the operator (ICF, 2014). Requirements to replace compressor rod packing at regular intervals, or capturing the gas from the seal degassing system, should be extended to existing equipment, in addition to being applied in the transmission sector.

Completions

EPA regulations (40 Code of Federal Regulations § 60 and 63) require that from January 1, 2015, all *gas wells* use RECs during the completions. Critically, however, this regulation does not apply to oil wells, which comprise an increasing proportion of all unconventional wells drilled in the US (Energy Information Administration, 2014b). This leaves venting and flaring restrictions on unconventional oil wells to state regulation. Therefore, states without controls on venting during oil well completions likely have significant quantities of methane and VOCs released during the flowback process. State level restrictions on unconventional oil well venting and flaring would likely reduce methane and VOC emissions.

The most effective controls to reduce methane and VOC emissions during well flowback on both oil and gas wells are requiring RECs; a second choice is to require all emissions be flared. Allen et al. (2013) report that sending all gas to flare or export can result in a 95-99% reduction in VOC and methane emissions. Flaring natural gas results in resource waste, contributes to CO2 emissions, and results in formation of nitrogen oxides (NOx) that can contribute to the formation of surface O3 so it is less desirable than an REC. Flaring, however, has a significantly lower climate impact than direct venting. Several states, including **Colorado** (Rule 805.b.(3)) and **Illinois** (62 **Illinois** Administrative Code 245) require the use of RECs for the flowback of all wells, except where it is technically or economically infeasible to do so. In the case of an exemption, the emissions must be flared in cases where it is safe to do so.

We recommend that states require an economic feasibility study to evaluate the cost of capturing gas from oil wells. These studies should require accounting for the full value of the gas, including natural gas liquids, which are rarely taken into account at present when making these judgments. In many locations, such as the Eagle Ford in **Texas**, the required pipeline infrastructure exists for capture of associated gas from oil wells, however there are no requirements for the reduced emission completions (RECs) of these wells even though wells are often tied into gas gathering infrastructure following completions.

Recommendations:

- RECs should be required during completion of unconventional oil wells in addition to the existing REC requirement for unconventional gas wells, except where the infrastructure does not exist for gas export. In those cases, all gas should be flared during the completion of the well.
- If justifying the non-capture of gas for economic reasons, the full value of the gas stream, including high-value components such as natural gas liquids, should be taken into account.

- Any flared gas could be taxed at a rate commensurate to that if the gas was being sold at market rates. This will provide further incentive for gas to be captured.

Flaring of gas from oil wells that would otherwise be vented is one of the lowest cost methods to reduce a significant quantity of natural gas emissions (ICF, 2014).

Liquids unloading
There are several methods that can be used to minimize the need to unload liquids from a well. These include installing smaller bore production tubing, or velocity tubing, to decrease the cross-sectional area of the production string, which increases the gas velocity in the well and decreases the liquid holdup. This has a disadvantage that it limits production volumes so is not always favored by operators (Smith, 2014). Alternately an artificial lift system can be installed, which provides downhole pumping to lift liquids to the surface. This is potentially expensive, however it is useful near the end of life of a well when a plunger lift system may not work (EPA, 2014d).

A plunger lift system is another method frequently employed for liquids unloading. In this technology, a plunger is dropped to the bottom of the well prior to liquid buildup exceeding certain limits. As the plunger rises it sweeps liquids up the wellbore, removing liquids from the well. This can be combined with smart automation that monitors the status of the well and automatically operates the plunger lift. If operated correctly, this system can potentially dramatically reduce venting, as gas production can continue to be directed into the downstream process or flared (EPA, 2014d).

According to ICF International (2014) estimates, the emissions per well for liquids unloading with plunger lift systems exceeded those of wells without plunger lifts. While gases are not directly vented to atmosphere from the top of a well with plunger lift systems, rapid changes in the liquid levels in storage tanks result in emissions from the tank vents. Cumulatively, the large number of loading events multiplied by the vented tank emissions per event result in a high emissions level. This demonstrates the need to have tank emissions controls, such as VRUs or emissions directed to flare. BP (Environmental Defense Fund, 2014a) has reported that with proper operator training, procedures and improved automation, it was able to reduce emissions from its plunger lift systems in the San Juan Basin by 99%.

Colorado regulations state that operators must use best management techniques to minimize venting during liquids unloading, and that the operator must be onsite during a planned liquids unloading event to minimize the extent of venting (EDF, 2014). Records and reporting requirements for liquids unloading events should be considered.

Storage tanks for wells producing liquids
Emissions can be controlled by the installation of a VRU or routing the gas to flare, which can result in a 95-99% reduction in emissions (EPA, 1991). Under 2012 regulation updated in 2013, the EPA requires tanks with controlled emissions of greater than six tons per year of VOCs (or 120 tons per year uncontrolled emissions) to reduce emissions by at least 95% and be subject to a number of reporting and verification requirements. **Colorado** is aiming for no vented emissions from storage tanks, and has extended these requirements to be applicable to tanks with uncontrolled emissions of six tons per year of VOCs (EPA, 2014d).

Given the stringency of these regulations, operators are considering moving to onsite storage in pressure vessels rather than storage tanks, as it is more cost effective to control emissions. An alternate option that is worth strong consideration is centralization of oil storage infrastructure. Instead of oil storage at the well-pad, oil could be pumped to a central facility, where emissions from tanks could be more cost effectively controlled. This has the added benefit of improving local air quality and minimizing truck traffic and the equipment footprint. In consultations for this report, some industry representatives noted that it is very likely that the industry will move toward this type of system given the multiple benefits of doing so, in addition to the difficulties meeting stringent no venting standards at many distributed sites.

We recommend that emissions control technologies be extended to all new and existing storage tanks with uncontrolled emissions exceeding 6 tons per year. Installation of vapor recovery units (VRUs) on existing tanks without controls is a very low cost method of reducing emissions, including VOCs (ICF, 2014).

Distribution
Although recent studies have documented significant natural gas leaks from the distribution system (Phillips et al. 2011), current state regulatory practices do not provide Local Distribution Companies (LDCs) with a strong incentive to address leaks. Indeed, almost all state utility

commissions allow natural gas distribution companies to claim methane leaks as “Lost and Unaccounted For” (LAUF), an explicit regulatory classification that treats gas leaks as an inherent cost of service and allows LDCs to recoup the revenue lost from gas leaks by charging higher prices on the end-user (Costello, 2013).

The market dynamic described above confronts natural gas pipeline companies with two choices: recover lost gas revenue through the LAUF pricing mechanism, or invest in infrastructure improvements and recover the investment through pipeline replacement allowances that can be built into the regulated price of gas paid by consumers. The key difference between the two scenarios lies in different cost recovery time horizons. LAUF gas costs are recovered immediately, as companies meet with regulatory commissions on a regular basis (often monthly) to adjust prices based on market fluctuations in routine operations and maintenance costs, supply and demand (Campbell, 2014; Costello, 2013 and Cleveland, 2012). In contrast, infrastructure projects are characterized by a longer cost recovery horizon, as these projects are only built into the price of natural gas during multi-year base rate negotiations (Cleveland, 2012). Between such negotiations, firms must carry infrastructure investment and interest costs forward until the base rate change is approved. This structure leads to a protracted cost recovery time horizon, where companies must successfully negotiate for changes in the base-rate price to cover infrastructure improvements over multi-year periods.

Calculating LAUF leakage rates represents a significant challenge for utility commissions, as gas meter inaccuracies make it difficult to distinguish true leakage rates from measurement error (Cleveland 2012). Ultimately, the presence of LAUF allowances undermines economic incentives for companies to invest in pipeline infrastructure improvements (Campbell 2014), while uncertainty over LAUF calculations hinders states’ ability to quantify the volume of fugitive natural gas emissions.

Recently, **New York State**, **Massachusetts** and **California** have undertaken novel policy initiatives aimed at changing the incentive structure facing LDCs in order to decrease leakage rates in the distribution system. New York's Public Service Commission currently negotiates allowable leakage rates with LDCs, and fines companies that exceed this rate. Fines are subsequently returned to ratepayers (Cleveland 2012). Similarly, **Massachusetts** recently approved the use of targeted infrastructure replacement factors (TIRFs) in rate setting negotiations with LDCs. TIRFs allow LDC's to recover capital expenditures on infrastructure improvements on an annual (rather than the traditional multi-year) basis (Cleveland, 2012). In both instances, by directly tying an LDC's return on investment to improvements in leakage rates, **New York** and **Massachusetts** may effectively incentivize firms to undertake large-scale projects that address their most prone distribution sites.

In addition to improving incentives for LDCs, states may direct LDCs to routinely inspect and repair distribution infrastructure upon the detection of a leak. **California**'s recent Natural Gas Leakage and Abatement Bill (SB-1371) requires LDCs to undertake LDAR programs throughout the distribution system. Recent economic studies, however, have shown that such LDAR programs remain one of the most expensive methane mitigation options on a dollar per cubic feet of methane-reduced basis.

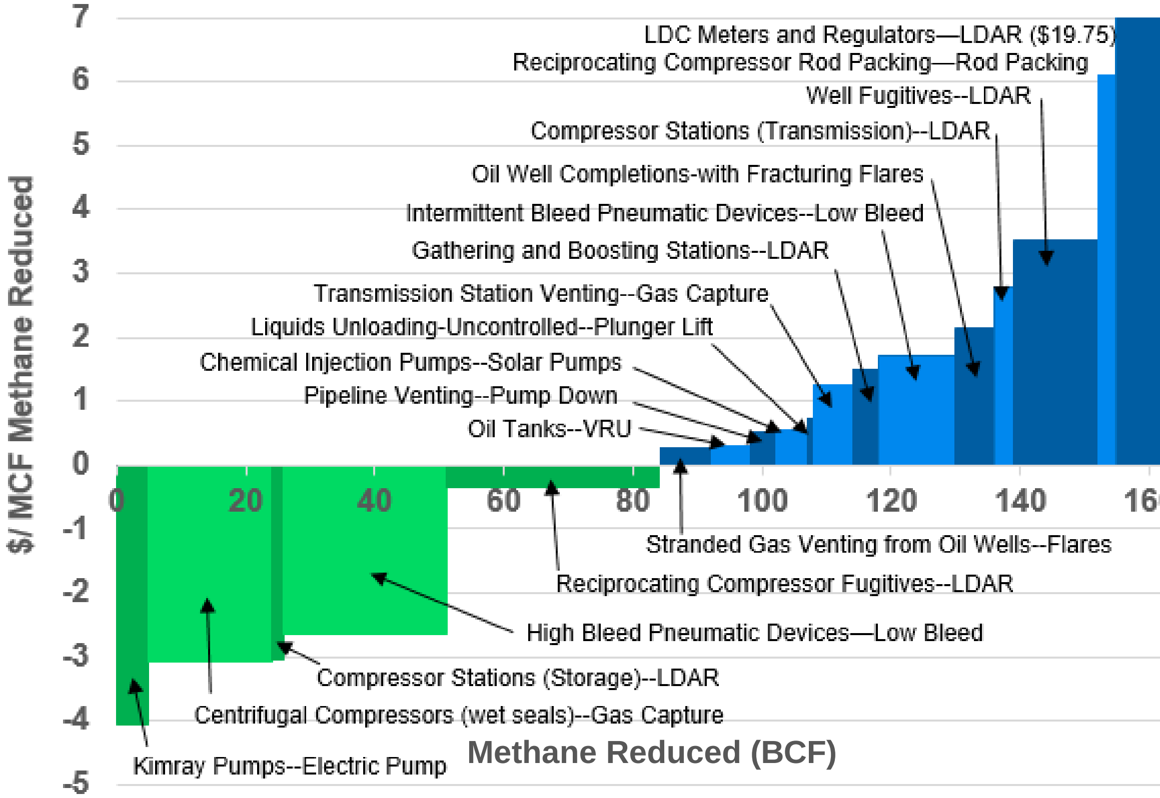
The following section summarizes several policy opportunities for states to consider when addressing leaks from the natural gas distribution system.

- Introduce financial incentives to reduce leakage rates: States can negotiate “allowable” LAUF rates during rate negotiations with LDCs, and fine companies for failing to meet performance benchmarks.
- Shorten cost recovery time horizons on infrastructure projects: Allow companies to recover capital expenditures on an annual basis to incentivize LDCs to more aggressively pursue infrastructure improvements and reduce leakage rates.
- Establish best practice requirements for leak surveys and patrols: Following the passage of **California**’s recent Natural Gas Leakage Abatement Bill (SB-1371), states can require LDCs to routinely inspect distribution lines and fix leaks upon discovery.

<u>**Cost Effectiveness of Technologies to Reduce Emissions**</u>

There are many opportunities to reduce natural gas emissions that are cost effective. The Environmental Defense Fund commissioned a report from ICF International that was released in 2014 (ICF, 2014). The report considered the top 22 sources of emissions from the oil and natural gas sector using EPA emissions inventory data, updated with the latest available peer reviewed data on natural gas emissions. Potential emission reductions and their costs were quantified, based on a forward projection of emissions to 2018. The costs saving calculations were based on data from federal (EPA NSPS data, EPA Natural Gas Star program), state and industry cost estimates. The key findings, based on the projected 2018 figures, are as follows:

Figure 6: ICF International Marginal Abatement Cost Curve for Selected Emissions Reduction Technologies



Source: ICF International, 2014

- Nearly 90% of emissions will come from existing (pre-2012) sources;
- 22 of the over 100 emissions sources will account for more than 80% of total emissions;
- Over 40% reduction in emissions is possible with available technologies at a net cost to gas producers of $0.66 per Mcf (1000 cubic feet) of methane, or $0.01 per Mcf when aggregated over all of the gas produced. Many reductions are possible at a net saving to the producer, with further savings at low cost;
- When more broadly applied to the US economy and consumers, the same measures are anticipated to result in a net saving of $100 million per year;
- Leak detection and repair, reduced venting of gas and replacement of high emission pneumatic devices are the largest opportunities for emissions reduction.

Figure 6 shows the marginal abatement cost curve for methane reductions based on a $4/Mcf gas price, close to the 5-year average Henry Hub Natural Gas Spot Price. Negative cost levels reflect that many emission reduction measures will result in a net saving for the gas producer.

When considered cumulatively, **all of the most cost effective emission reduction measures from Kimray pump replacement through to and including rod packing replacement could be completed at net cost benefit to the gas producers. When economy-wide value is considered, all 22 proposed emission reduction measures could be completed at a net positive benefit.**

Cost sensitivities are also considered for $3 and $5/Mcf gas prices, and while the aggregate cost increase overall, many measures that have net cost benefits or low producer cost remain cost effective. When costs are considered economy wide, the cost benefits of the emission reduction technologies become even more effective.

CHAPTER 3: RISKS TO WATER RESOURCES AND LEADING MITIGATION OPTIONS

Unconventional oil and gas development presents risks to both the availability and the quality of water resources. Water quality issues can be broadly divided into two categories: risks due to (1) subsurface activities and those due to (2) surface activities. Risks from subsurface activities, due to the nature of the subsurface environment, are difficult to identify and may occur on very long timescales compared with development itself. In contrast, risks from surface activities are more readily identified, often stem from relatively preventable occurrences such as spills and leaks or from treatment and disposal methods operators control directly, and occur on shorter timescales during development. Risks to water quality occur in the local vicinity to wells and well pads due to drilling and fracturing and associated surface activities, depicted in **Figure 2**, while risks to water availability are more regional in nature.

Risks to Water Availability

A horizontal well requires between 2 and 7 million gallons of water for fracturing depending on local geology, as well as the size and type (oil or gas) of well (Department of Energy, 2014b; Vidic et al., 2013). Although the quantity of water used appears quite large, unconventional development usually represents a small fraction of municipal and industrial water use in communities (Schumacher & Morrissey, 2013). However, unconventional development often occurs in water-stressed regions of the country. Nearly half of oil and gas wells hydraulically fractured between January 2011 and May 2013 were developed in regions with high or extremely high water stress (Ceres, 2014). Already facing significant strains on local water supplies in meeting existing demand for human and industry needs, water-stressed or drought-prone regions require especially careful management of water appropriations.

Source and Quantification of Impact

Even in areas with sufficient water supply, mismanagement of withdrawals can disrupt water flows and have significant effects on aquatic ecosystems, particularly when extracting water from small streams in low flow conditions (Richardson et al., 2013). If companies develop multiple wells and withdraw water around the same time, impacts multiply.

Current Policy Landscape

In order to help monitor and coordinate water withdrawals, states use a variety, and sometimes a combination, of regulatory tools including: permits, registration prior to withdrawals, and other states require reports of final amounts withdrawn from a source. Wide variation exists across states regarding water quantity management. While some states do not require permits at all, most states require permits for significant withdrawals of water. RFF's survey of state regulations found that 26 of 30 states require some type of permitting for water withdrawals (referring to surface and/or subsurface water) (Richardson et al., 2013). Of those 26 states, only half require permits for all withdrawals, while the other half require permits for withdrawals above a certain amount (Richardson et al., 2013). **Illinois**, **Indiana, Ohio, West Virginia, and Vermont** require both a permit and reporting for water withdrawals (Richardson et al., 2013). Of the eight states that required reporting, as of June 2013, only **Louisiana** required it for all withdrawals. States water sources and needs vary, as do the type of requirements that would best suit these needs.

Although API best practice states "operators should consider options for the recycling of fracture treatment flow back fluid," in general state regulation does not explicitly discuss recycling of wastewater for future hydraulic fracturing (*API Guidance Document HF2*, cited in Richardson et al., 2013, p. 52). As a result, RFF did not include policies to encourage recycling or reuse in their comparative study covering state shale gas related regulations as of March 2013. While typically state regulation does not directly mention recycling, by default RFF assumes that it is legal in all states (Richardson et al., 2013, p. 52). Some states do mention or encourage recycling in their regulations, but many require permits. For example, at the time of writing, RFF recorded that Oklahoma, the state that provided the most options for drill fluids and cuttings, has regulations that specifically includes the use of a "**permitted** recycling/reuse facility" (Richardson et al., 2013, p. 56). In addition, out of the 31 states surveyed, only a few had specific regulations for wastewater reuse, although none specifically mandated this practice (Richardson et al., 2013, p. 56). Utah suggests that "recycling should be used whenever possible and practical" (Utah Admin. Code r. 649-9-2.2.1 cited in Richardson et al., 2013, p. 56).

The next section highlights examples of states using different regulatory tools to improve water withdrawal coordination and management, and examines **Texas**' regulatory changes to encourage recycling and reuse.

Leading Technologies and Practices to Mitigate Impacts

Existing research on water availability says that recycling and reuse of water along with regional water withdrawal management and coordination can reduce risks to water sources in both water scarce and rich regions (Ceres, 2014). Ceres, a nonprofit organization focused on business and investor leadership on sustainability challenges such as water scarcity, created a list of guidelines for states to consider on leading regulatory practices regarding water sourcing that this report also endorses (2014). Ceres recommended guidelines include:

- Catalogue the consumptive water use from hydraulic fracturing operations, including sources of water used and the amounts recycled (**Ohio** requires operators to identify each proposed source of ground & surface water that will be used, but does not require post-drilling disclosure of actual volumes of freshwater and recycled water used).
- Create integrated management structures for joint oversight of ground and surface water.
- Require information on how operators plan to manage wastewater streams including final disposal of water.
- Realize that higher disclosure requirements alone will not solve water sourcing impacts and risks, and must be accompanied by proactive water management plans that include monitoring and enforcement components.
- Ensure that water-sourcing oversight is independent from the department granting oil and gas permits to minimize conflicting mandates and objectives.
- Create systems of incentives and/or mandate requirements to encourage recycling and non-freshwater use (such as in **Texas**).
- Implement measures to prevent invasive species transfers.
- Provide more resources to map and monitor groundwater resources, including remote aquifers and brackish water resources, across North America.
- Reduce reliance on aquifer exemptions and create incentives to minimize use of deep well injection sites (Ceres, 2014 p. 37).

Water withdrawal tracking and coordination of regional water withdrawal management

Michigan has developed a nationally recognized GIS-based water withdrawal assessment tool, which determines potential impacts on aquatic ecosystems (Fitch, 2014). **Michigan** now requires the oil and gas industry to use this tool when applying for a permit (Michigan FAQ). In partnership with Louisiana State University, **Louisiana** established a network of groundwater monitors in the area supplying the Haynesville play to collect baseline data before shale development commenced (Ceres, 2014). **Pennsylvania** requires a water management plan for shale gas production that covers full lifecycle of water, including identification of water source, amount wanting to withdrawal, and an analysis of withdrawal impact on the source. **Pennsylvania** also requires daily monitoring and compliance data from operators (Ceres, 2014).

Encouraging wastewater reuse and recycling

In order to incentivize recycling and reuse of water it is imperative to understand the economic factors that influence operators' decisions to recycle or not. Key variables that operators consider when determining their water management practices include: (1) the number of wells, (2) volumes of flowback and produced water, and (3) the proximity of these sources to be able to aggregate sufficient waste water to make recycling cost effective (Boschee, 2014). In the Eagle Ford area in **Texas**, low flowback and produced water volumes complicate the logistics of recycling and reuse. A study of the Eagle Ford play reports that the ratios of flowback/produced water to hydraulic fracturing fluid are generally less than 5 percent within the first month of well completion (Scanlon, 2014). This low ratio makes it difficult for operators to collect sufficient water to support recycling. In addition, in **Texas** recycling is generally not economically advantageous, thanks to relatively cheap injection wells (Scanlon, 2014).

In spite of the poor economic case for recycling in much of the state, spurred by drought and water sourcing issues, **Texas** prioritizes water conservation. The **Texas** Railroad Commission became the first state oil and gas regulatory agency to use regulations to facilitate an easier process for operators to recycle hydraulic fracturing wastewater (GWPC, 2014). In April 2013, the Commission amended Rule 3.8 of the **Texas** Oil and Gas Division in order to encourage recycling by loosening restrictions and allowing operators to sell their recycled water to other operators. These changes eliminated the need for operators to acquire a permit to recycle from the Commission as long as operators recycle fluid on their own lease or transfer their fluids to another operator's lease for recycling (GWPC, 2014). It also allows operators to use pits (subject to pit construction, use, maintenance, and operation rules) during the recycling process, without a permit.

Beyond the guidelines for leading regulatory practices, Ceres notes a need for increasing information sharing and collaboration among state and local bodies tasked with regulating oil and gas development, as well as those that oversee agricultural and municipal water use. Examples of existing platforms to facilitate improved cooperation include: the Ground Water Protection Council's Risk Based Data Management System and Intermountain Oil and Gas Project and database. STRONGER has formed a workgroup including representatives from state and federal agencies, industry, and environmental groups to develop state fluid recycling program guidelines. These guidelines will likely include both flowback and produced water. After the workgroup proposes a draft of guidelines, the STRONGER Board will establish a comment period before approving final guidelines.

Subsurface Risks to Water Resources

Groundwater is a major source of drinking water in many of the areas where unconventional oil and gas development is occurring. The primary risk from subsurface activities associated with this development is contamination of groundwater aquifers with hydraulic fracturing fluids or hydrocarbons and associated possible harm to public health or ecosystems.

Hydraulic fracturing fluid consists predominantly of water, with proppant (grains such as sand that lodge in the created fractures to hold them open) and chemicals (typically acid, friction reducers, corrosion inhibitors, gelling agents, surfactants, and biocides) added to enhance its properties. According to the Groundwater Protection Council (GWPC) and Interstate Oil and Gas Compact Commission (IOGCC), these chemicals constitute 0.8% of fluid volume on average. Many of the chemicals are not harmful, but from 2005 to 2009 there were at least 29 different chemicals used that could be hazardous in drinking water. In addition, hydraulic fracturing fluid is often well above drinking water salinity limits (GWPC and IOGCC, 2014).

The fluid most likely to migrate into groundwater supplies is natural gas, due to its strong buoyancy (Watson and Bachu, 2009). Although methane is not itself considered a health hazard in drinking water, it may accumulate inside water wells, buildings with wells, or water storage tanks, where it may become flammable or explosive (Kappel and Nystrom, 2012). Methane dissolved in groundwater can also lead to anaerobic bacteria growth that, in turn, causes water and air quality issues (Vidic et al., 2013).

Sources and Quantification of Impacts

There are two means through which hydraulic fracturing fluids or hydrocarbons can potentially enter groundwater aquifers due to subsurface activities: (1) through well integrity deficiencies, which can arise during drilling, during a well's productive life, or after production is complete; and (2) through hydraulic fracturing. Although numerous reports and studies have been released recently, critical gaps remain in scientific knowledge of the potential subsurface impacts (Jackson, R.E. et al., 2013).

Well integrity

Well integrity refers to the ability of a well to isolate all fluids flowing within the well casing from the environment outside of the well and to prevent fluids from geological media penetrated by the wellbore from migrating along the space between the outer casing and rock (the annulus). Well integrity is critically important in preventing contamination of groundwater aquifers and the ground surface with fluids including gas, oil, brine, and hydraulic fracturing fluids, in addition to preventing gaseous emissions from leaking into the atmosphere.

To achieve well integrity, companies install multiple concentric steel tube casings in the wellbore and pump cement into the outer annulus to create sealed barriers at appropriate intervals. These intervals may include groundwater aquifers (as illustrated in **Figure 2**) and zones of potential hazardous inflow such as the target producing formation or intermediate formations containing high-pressure gas. There are several possible leakage pathways from compromised wells, including interfaces between rock and cement, within cracked or degraded cement, or through corroded or failed casing. Cement deficiencies provide the most likely and common path for gas leaks (Gasda et al., 2013; Gorody, 2012). Deficiencies may be caused by issues such as cement shrinkage and cracking, channeling by drilling fluid or high pressure gas, or poor bonding at the cement-rock interface (Vidic et al., 2013). Best practice cementing materials and methods can minimize these issues. A study of over 20,000 wells found that the presence of a high quality, effective cement seal is the most important factor for well integrity, and that the plugging method used for abandoning wells is also very important (Watson and Bach, 2009).

Investigations into well integrity in existing oil and gas fields have shown that a significant percentage of wells experience integrity issues, usually identified by increased pressure in one or more casing annulus indicating fluid inflow (Davies et al., 2014; Watson and Bachu 2009). Between 3.4% (Vidic et al., 2013) and 6.3% (Davies et al. 2014; Ingraffea et al., 2014) of unconventional wells in the Marcellus Shale have integrity deficiencies. Locally up to 9.8% of unconventional wells in the largest producing region of northeast **Pennsylvania** experience an integrity issue (Ingraffea et al., 2014). It has also been observed that non-vertical wells and wells drilled during periods of rapid development (such as the shale boom) have higher rates of integrity issues (Watson and Bachu, 2009).

Research has also whether recent unconventional oil and gas development has caused groundwater contamination, in particular by methane. It has been found that distance from unconventional gas wells is the most important factor determining concentration of thermogenic methane and other hydrocarbons that are constituents of natural gas in water wells overlying the Marcellus Shale (Jackson, R.B. et al., 2013; Osborn et al., 2011). Analyses of groundwater contaminated by natural gas overlying the Marcellus and Barnett shales suggest migration from underlying gas formations along faulty wellbores is the most likely source (Darrah et al., 2014). Methane concentrations in groundwater are naturally high in many oil and gas producing regions, however, making it difficult to determine whether methane in any particular location resulted from oil and gas development (Kappel and Nystrom, 2012; Wilson, 2014). Contamination is also not evident in all plays: an investigation for the Fayetteville Shale in **Arkansas** found no evidence of contamination due to unconventional gas wells (Warner et al., 2013a). A lack of baseline studies in most areas makes identifying the source of contamination difficult (Schon, 2011).

Hydraulic fracturing

A prominent concern regarding hydraulic fracturing is the possibility of fractures propagating from the target formation up to groundwater aquifers, enabling contamination by fracturing fluids and/or hydrocarbons. According to available evidence it appears very unlikely that hydraulic fractures could directly connect with and contaminate groundwater aquifers in major unconventional oil and gas plays due to the significant distance separating fractures from aquifers (Fisher and Warpinski, 2012; Flewelling et al., 2013). Some uncertainty exists, however, regarding the accuracy of the methods used for determining fracture locations (Jackson, R.E. et al., 2013).

While induced hydraulic fractures are unlikely to create a direct pathway to the surface or groundwater aquifers, there is evidence they may intersect other pathways – in particular, adjacent wells. In Alberta, Canada, hydraulic fracturing in a new horizontal well created a connection to an adjacent existing oil well that was targeting the same formation 6,070 feet below ground, and resulted in hydraulic fracturing fluids being produced out of the existing well. The incident was attributed to inadequate spacing between the adjacent wells (ERCB, 2012).

In many regions where unconventional production occurs, abandoned wells also exist from earlier oil and gas production. In **Pennsylvania**, for example, many of these wells are not plugged, plugged poorly by modern standards, or severely degraded, and often leak hydrocarbons (Kang et al., 2014). Most of these older wells are not recorded on any official register and potentially hundreds of thousands of such wells exist. While most are likely to be relatively shallow compared to the current unconventional targets, it is possible that some are deep enough for hydraulic fractures to reach them.

<u>Case Study – Subsurface Risks in Pavillion, Wyoming</u>

An EPA investigation into potential groundwater contamination in Pavillion, **Wyoming** was conducted following complaints from residents in 2008 about water quality from their water supply wells, which overlie an active gas well field. While the case is controversial and no final report or attribution has been made, the facts are worth considering. A draft report from the investigation found several chemicals used in hydraulic fracturing fluid present in the deeper zone of the primary drinking water aquifer in the region (EPA, 2011b). The geological structure in Pavillion is atypical of major unconventional plays: the target gas-producing zone is relatively shallow and part of the lower portion of the formation that contains the primary groundwater aquifer in the region. The hydraulically fractured wells in Pavillion are as shallow as 1,220 feet below ground and groundwater wells are as deep as 800 feet. Surface casings for most of the gas wells do not extend below the deepest water wells in the area, and many gas wells have uncemented zones within the aquifer formation. While it remains unknown if the groundwater contamination resulted through wellbore pathways, direct migration from hydraulic fractures, or (less likely) from contaminated disused surface pits, it is likely that it did result from gas development.

The Pavillion case does not have direct implications for the level of risk in the major unconventional oil and gas plays such as the Barnett, Marcellus, Bakken, and Eagle Ford Shales, which typically lie between 5,000 to 12,000 feet below ground with a number of low-permeability barriers between them and groundwater aquifers (DOE/NETL, 2014). However, the facts of the case do suggest that comprehensive characterization of the local geology and adjacent wells is required to assess the risk of hydraulic fracturing operations and to enable production wells to be designed to adequately protect aquifers.

Current Policy Landscape

Regulation of subsurface activities falls almost completely under state jurisdiction. Injection of fluid into the subsurface usually falls under jurisdiction of the Safe Drinking Water Act and would typically be regulated by the EPA Underground Injection Control (UIC) program. However, hydraulic fracturing is exempt from regulations under the Safe Drinking Water Act (unless diesel fuels are used in the fracturing fluid).

Leading Technologies and Practices to Mitigate Impacts

Current and proposed leading practices to address subsurface risks largely come from performance standards created by industry and non-governmental organizations and regulations in leading states. Particularly useful sources for determining current leading practices and assessing the effectiveness of different state regulations to protect water resources include the American Petroleum Institute (API), Center for Sustainable Shale Development (CSSD), and Groundwater Protection Council (GWPC).

Casing and cementing requirements

High quality cementing is the most critical factor in maintaining well integrity (GWPC, 2014; Watson and Bachu 2009). Ensuring a high quality, effective cement seal requires careful selection of cement properties and appropriate zones to cement depending on subsurface conditions, preparation of the wellbore before emplacing the cement, and evaluation and remediation (if required) after emplacement. For example, high pressure gas zones are a hazard and challenging to cement adequately: to achieve an effective seal, cement type and density must be carefully selected depending upon the exact subsurface conditions and drilling mud must be properly removed from the wellbore before cementing (Vidic et al., 2013).

Stringency of cementing and casing regulations vary significantly between states. While all 27 major producing states require surface casing to be cemented from bottom to top to protect groundwater aquifers, only 17 states require corrective action to be taken before drilling resumes if a deficiency is encountered during casing and cementing, 15 states require intermediate casing to be cemented to isolate hazardous zones, and only eight states require cement to meet API standards (GWPC, 2014). Leading states include **Ohio**, **North Dakota**, and **Wyoming**, which require that casing and cementing plans be submitted when applying for a drilling permit (Ohio Admin. Code 1501:9-1-02; GAO, 2012), and **Ohio** also requires cementing reports be provided upon completion of cementing (Ohio Admin. Code 1501:9-1-08).

Cement evaluation

Cement evaluation with acoustic or other down-hole tools can determine whether there are deficiencies in the cement behind the well casing. The API recommends using these evaluations in combination with other information such as mechanical integrity tests to determine adequacy of cementing (API, 2009). 14 states, including **Ohio, Colorado,** and **Texas**, require cement evaluation in certain circumstances and the number continues to increase (GWPC, 2014). The average cost of cement evaluation is approximately $9,000, which is less than 0.3% of the cost of a typical unconventional well (BLM, 2012).

Mechanical integrity tests

Mechanical integrity tests, or pressure tests, can be extremely useful to determine well integrity, in order to remediate before drilling continues beyond each casing and cementing stage, or before hydraulic fracturing begins. The API states that the performance of these tests is ‘critical’ to ensuring well integrity and recommends that integrity monitoring should continue throughout the life of a well (API, 2009), yet few states currently require these tests to be performed for each casing. **Illinois** and **North Dakota** are examples that require integrity tests for each casing (62 Illinois Administrative Code 245; GAO, 2012). Eight states require monitoring and recording of important data during fracturing operations that may indicate well integrity, such as annular pressures (GWPC, 2014). A leading example, **Ohio** requires the installation of equipment to monitor annular pressures throughout well life, notification of the regulator and remediation if deficiencies are found, and well plugging if integrity cannot be restored (Ohio Administrative Code 1501:9-1-08). The average cost of one mechanical integrity test is approximately $10,000, which is less than 0.3% of the cost of a typical unconventional well (BLM, 2012).

Plugging and abandonment

Many oil and gas producing regions have legacy issues of abandoned wells leaking hydrocarbons due to poor or non-existent plugging (Kang et al., 2014). Ensuring proper plugging of current wells is critical to prevent future leaks. Most states recognize the importance of proper plugging, and 26 of the 27 major producing states require notice of plugging so that inspectors may be present.

Area of review

The CSSD performance standards require that an area of review be established prior to drilling a well, within which a comprehensive characterization of the geology (e.g. presence of confining rock layers, faults) and potential leakage pathways (e.g. adjacent active or abandoned wells) must be conducted, a risk analysis performed, and identified risks adequately addressed (CSSD, 2013). This approach is modeled on current regulations for the EPA's UIC program for wells that inject fluids underground, to which hydraulic fracturing is not subject due to its exemption from the Safe Drinking Water Act. Many states already require some of the elements of an area of review process, such as identification of abandoned wells or evaluation of geological barriers, but only four states require them as part of a comprehensive area of review evaluation (GWPC, 2014). A comprehensive evaluation ensures that all potential risks are considered in fracturing treatment and well design.

Pre and post-drill water testing

It is important to establish baseline water quality so that any changes as a result of development may be identified and addressed. The CSSD performance standards require monitoring of surface water and groundwater quality prior to drilling to establish a water quality baseline, periodic monitoring for a year after hydraulic fracturing, and additional monitoring if a well is re-fractured (CSSD, 2013). At present only eight states require pre-drill testing of adjacent wells (GWPC, 2014) and only **Illinois** requires both pre-drill and periodic post-completion monitoring (62 Illinois Administrative Code 245).

Fracturing fluid disclosure

Compulsory disclosure of chemical ingredients for hydraulic fracturing fluids has become common, with over 20 states requiring disclosure, including 16 requiring or allowing public disclosure to the FracFocus chemical disclosure registry (GWPC, 2014). A common controversial element of disclosure requirements in most states is the ability for companies to avoid disclosing chemical additives that are considered 'trade secrets'. The CSSD standards address this concern by requiring that only the chemical family names of ingredients for such trade secret additives be disclosed (CSSD, 2013). Leading examples for disclosure regulations include **Illinois**, **Pennsylvania** and **Texas**, which require chemical family name disclosure for trade secret ingredients and include provisions for disclosure of these chemicals to healthcare professionals when required for affected patients (62 Illinois Administrative Code 245; GAO, 2012).

Approvals and disclosure

Two key themes in leading practices, and the direction state regulations are moving, involve (1) greater disclosure requirements to regulating authorities and the public and (2) requiring approvals for more actions. None of the aforementioned practices involve the implementation of new technologies or methods; they currently exist as standard practice for industry leaders. Enhanced approvals and disclosure are important so that companies can demonstrate adherence to these standards and to ensure uniform adherence by all industry participants. Disclosure can also help address community fears that may arise due to a lack of information about development occurring around them and perceptions of an unregulated industry.

It is becoming more common for regulators to be notified of critical stages of development so that inspectors may be present. Almost all states require this for well plugging, and 11 states, including **Ohio** and **Pennsylvania**, now require notification of commencement of casing and cementing operations (GWPC, 2014; GAO, 2012). Currently 21 states require reporting of hydraulic fracturing operations, ten states require separate permitting for hydraulic fracturing, six require public notice of hydraulic fracturing and at least four require notification to regulating authorities so that inspectors may witness the operations (GWPC, 2014), including **Colorado**, **Ohio** and **Pennsylvania** (GAO, 2012). **Illinois** is again a leading example, with separate permitting required for high volume hydraulic fracturing, and notification of and approval from the regulator required 48 hours before each fracturing treatment (62 Illinois Administrative Code 245).

Recommendations:

- Well integrity: The highest standards of casing and cementing should be required; casing and cementing plans should be submitted as part of well drilling permit applications to demonstrate adequate design for the local subsurface conditions, and casing and cementing reports submitted following completion. Comprehensive evaluation and remediation of well integrity should be required during well casing and cementing and continue throughout well life.
- Hydraulic Fracturing: Comprehensive area-of-review-type risk assessments should be undertaken before fracturing as part of the approval process. Pre-drill water testing must be mandatory as well as periodic post-completion monitoring. Fracturing fluid disclosure must be mandatory and chemical family names should be disclosed for 'trade secret' additives.
- Both: Enhanced approvals and disclosure are needed. Regulators should be notified at crucial stages (e.g. well casing and cementing, hydraulic fracturing) so that inspectors may be present; hydraulic fracturing should have additional approval to well drilling to

demonstrate that comprehensive risk assessment has been conducted; evaluations of well integrity should be required regularly during casing and cementing and production, and any integrity deficiencies should be reported to regulators and must be remediated. Regulators also need to be able to impose significant penalties if infractions occur.

Surface Water Contamination Risks

The health of surface waters directly impacts drinking water quality and ecosystem function, so monitoring and addressing surface water impacts of unconventional oil and gas development are critical. The primary potential risk to surface waters stems from the large volumes of wastewater created during the hydraulic fracturing process. According to a survey of industry experts, alternative fracturing fluids, such as hydrocarbon liquids or compressed gases, are unlikely to replace water-based fracturing fluids anytime in the next several decades (Mauter and Palmer, 2014). Therefore, reducing risks to surface water from hydraulic fracturing wastewater contamination will remain a priority.

Hydraulic fracturing wastewater consists of the fracturing fluid, in addition to the flowback and produced water from the formations. It contains a multitude of constituents, which can be broken into main contaminant classes based on their source and chemical behavior. Several of these contaminant classes pose significant risk to surface water quality, as well as ecosystem and human health. The key contaminants considered most hazardous and warrant increased attention include: total dissolved solids (TDS) or salts, the industrial additives benzene, toluene, ethylbenzene, and xylene (BTEX collectively), radionuclides, and disinfection byproducts.

Sources and Quantification: Pathways of Contamination

The potential introduction of untreated or inadequately treated wastewater to surface waters is the primary concern. Hydraulic fracturing wastewater has three main pathways after production, each with their own contamination risks: (1) storage, (2) treatment for recycling/reuse or disposal, and (3) final disposal.

Storage

Wastewater often requires storage on-site both before and after treatment for recycling and reuse, or prior to off-site treatment and disposal. Storage options typically include pits and tanks with the main risks of leaks or spills.

Treatment for recycling, reuse, or disposal

Hydraulic fracturing wastewater can be directly reused on-site, often after freshwater blending. Treatment for recycling, both on-site and off-site, also readies wastewater for further hydraulic fracturing. Wastewater can also be disposed of at publicly owned treatment works (POTWs), centralized waste treatment facilities (CWTs), or deep injection wells.

POTWs, which are intended for municipal wastewater, are not designed to remove the high salt (or total dissolved solids) loads in hydraulic fracturing wastewater. Variable flow rates caused by the intermittent addition of hydraulic fracturing wastewater may also disrupt treatment processes (Hammer et al., 2015). In 2011, the **Pennsylvania** Department of the Environment (PADEP) issued a voluntary moratorium on all disposal of Marcellus Shale wastewater to POTWs that discharge to surface waters.

CWTs can provide wastewater treatment for (1) further hydraulic fracturing through operators purchasing treated wastewater from the CWT or (2) final disposal to surface waters. Concerns remain over whether existing CWTs provide adequate treatment for surface water disposal of hydraulic fracturing wastewater, or if treatment upgrades are necessary (Ferrar et al., 2013; Warner et al., 2013b).

Final disposal

Hydraulic fracturing wastewater can be transported for final disposal to deep injection wells, which is the top disposal option explicitly mentioned and allowed by state regulations (30 of 31 states), followed by disposal at treatment facilities (13 of 31 states) (Richardson et al., 2013, p. 54). The federal government regulates Class I and II injection wells under the Underground Injection Control (UIC) program of the Safe Drinking Water Act (SDWA), but can be administered by approved state programs after a state application for primacy. Hydraulic fracturing wastewater can be disposed of in Class II wells, which are designed for fluids from oil and gas production as well as hydrocarbon storage, instead of Class I wells that are specifically designed to accept hazardous waste and have more stringent disposal regulations. Many states, including **Pennsylvania**, do not have favorable geology for deep wells, so wastewater is often trucked to other states, such as **Ohio**, increasing the risk of accidental spills.

Current Policy Landscape

Several federal regulations pertain to surface water impacts from hydraulic fracturing wastewater. In addition, key exemptions to these federal regulations contribute to the risk of surface water contamination from hydraulic fracturing wastewater.

The Clean Water Act bans the direct discharge of wastewater from oil and gas into surface waters (40 Code of Federal Regulations § 435c). In 1987, the CWA was expanded to require National Pollutant Discharge Elimination System (NPDES) permitting for storm-water runoff, but oil and gas production were exempted. The Energy Policy Act (2005) further added oil and gas construction to this exemption.

Under the Safe Drinking Water Act (SDWA), an Underground Injection Control (UIC) permit is typically required when fluid is injected into the subsurface. However, the Energy Policy Act of 2005 created an amendment to the SDWA, commonly referred to as the "Halliburton Loophole", which exempts hydraulic fracturing from the UIC program (Safe Drinking Water Act Sec. 1421, 42 U.S.C. § 300h), except when using diesel-based additives in the hydraulic fracturing fluid. Diesel was excluded from the exemption, because it is known to contain toxic contaminants. A UIC permit is required for hydraulic fracturing wastewater disposal in deep injection wells, typically Class II wells.

Hydraulic fracturing wastes are exempted from regulation under Subtitle C of the Resource Conservation and Recovery Act (RCRA), which handles hazardous waste (Rich and Crosby, 2013). Hydraulic fracturing wastes are listed as "special wastes", instead of "hazardous wastes", and do not require additional specialized handling.

Key Contaminants

If hydraulic fracturing wastewater were to come in contact with surface waters, the following contaminant classes pose the greatest risk to surface water quality, human health, and ecosystem function.

Total Dissolved Solids (TDS)

High total dissolved solids (TDS) characterize hydraulic fracturing wastewater (Ferrar et al., 2013; Hammer et al., 2012; Vengosh et al., 2014). TDS, a key parameter of water quality, is defined as "a measure of the total ions in solution" (Crittenden et al., 2012), including both inorganic salts and organic material. TDS below 1,000 mg/L characterizes freshwater, while seawater contains about 35,000 mg/L TDS. The TDS of hydraulic fracturing wastewater range from below that of seawater to seven times it (Vengosh et al., 2014). High TDS can extremely harmful to freshwater ecosystems (Vengosh et al., 2014).

High TDS in drinking water does not necessarily pose a human health risk, depending on the profile of the constituent ions, but it can impact the aesthetic qualities of drinking water (EPA, 2013a). TDS in drinking water are included in the EPA's National Secondary Drinking Water Regulations, non-mandatory guidelines for contaminants that do not pose risks to human health, but can impact the aesthetic qualities of drinking water (EPA, 2013a). These guidelines recommend that drinking water treatment plant operators serve water with less than 500 mg/L TDS. To meet these standards, it is important to reduce TDS in wastewater treatment operations before it is released to surface waters, which often serve as inputs to drinking water plants. In addition, some of the individual constituents of TDS can pose health and environmental risks and are separately regulated.

Industrial additives (BTEX)

A range of substances are added to hydraulic fracturing fluid, including sand, surfactants, biocides, and friction reducers to help effectively fracture the subsurface rock (Vidic et al., 2013). Companies are not required to disclose their precise mix of additives in order to protect their proprietary information, so tracking water contamination from hydraulic fracturing fluid can be difficult.

Diesel-based additives, however, are regulated under the UIC permit program, because they contain toxic volatile organic compounds, including benzene, toluene, ethylbenzene, and xylene (BTEX), which are linked to cancer and other diseases (EPA, 2004). A recent study of the FracFocus database found that many unregulated non-diesel additives contained more BTEX than the regulated diesel-based additives, as **Table 2** demonstrates (Schaeffer and Bernhardt, 2014). This regulatory gap concerning non-diesel additives creates a potential pathway for harmful exposure and contamination. BTEX may also naturally occur in hydrocarbon-producing subsurface formations and be carried to the surface with the produced water (Hammer et al., 2012, Chen et al., 2014). Therefore, regulation of BTEX-containing additives, diesel-based or not, is important for minimizing BTEX exposure, followed by appropriate treatment of any residual or naturally-occurring contamination.

One report measured BTEX levels in hydraulic fracturing wastewater ranging from undetectable to 5.5 mg/L (Hammer et al., 2012). In comparison, EPA's maximum contaminant levels for benzene, toluene, ethylbenzene, and xylenes in drinking water are, respectively, 0.005 mg/L, 1 mg/L, 0.7 mg/L, and 10 mg/L (MDE, 2007; EPA, 2013b).

Radionuclides
Hydraulic fracturing wastewater can carry naturally occurring radionuclides in the subsurface geology to the surface and into contact with humans. These contaminants are referred to as naturally occurring radioactive material (NORM) or sometimes, because human activity can concentrate the radionuclides, as technologically enhanced NORM (TENORM). Radioactivity poses risks to workers in the unconventional oil and gas industry as well as to the environment and the general population, and remains a policy concern.

The EPA's Maximum Contaminant Levels (MCL) for combined ^{226}Ra and ^{228}Ra, gross alpha particle activity, beta particle and photon radioactivity, and uranium are 5 pCi/L, 15 pCi/L, 4 mrem/year, and 30 µg/L, respectively. States set radioactivity limits for municipal landfills, which range from 5 to 50 pCi/g (Brown, 2014). One study found ^{226}Ra and ^{228}Ra, with half-lives of 1,600 and 5.75 years, respectively, in Marcellus Shale gas wells at concentrations ranging from 73 to 6,540 pCi/L, which is 13 to 1,300 times greater than the EPA MCL (Haluszczak et al., 2013). However, regulations on particular components of radioactivity may be insufficient, because a wide range of radionuclides naturally occur in the subsurface (Brown, 2014; Rich and Crosby, 2013).

During wastewater treatment, NORMs can accumulate in treatment residuals and pose health and environmental risks (Warner et al., 2013b; Vengosh et al., 2014; Zhang et al., 2014). While wastewater treatment plants may reduce radionuclide levels in the effluent, even small amounts have been found to accumulate over time in stream sediments near the discharge point, with one study site reporting ^{226}Ra levels 200 times higher than upstream sediments (Warner et al., 2013b). Therefore, if NORMS are not adequately removed during wastewater treatment, they can pose a risk to drinking water treatment facilities as well as freshwater ecosystems.

Disinfection byproducts
Disinfection is an integral part of drinking water treatment to limit disease-causing pathogens (EPA, 2013c). Despite the obvious benefits of disinfecting drinking water, high levels of inorganic species combined with natural organic matter present in the water can react with the disinfecting species to produce disinfection byproducts (DBPs), which are toxic carcinogens. Balancing the removal of pathogens by disinfection with the creation of DBPs is a primary concern in drinking water treatment (Crittenden et al., 2012). The EPA's Stage 2 Disinfection Byproduct Rules regulate acceptable levels in drinking water (EPA, 2006).

Hydraulic fracturing wastewaters can increase DBP production by increasing levels of bromide and iodide in surface waters, with one set of laboratory tests finding that water containing as low as 0.1% hydraulic fracturing wastewater triggered an increase in trihalomethanes (THMs) of 70-140% during chlorination (Hladik et al., 2014; Parker et al., 2014; Sun et al., 2013).

Table 2: Ethylbenzene, Toluene, and Xylene in Fracturing Fluids (units are percent by volume)

Product	Ethylbenzene	Toluene	Xylene
Diesel	1.0	<0.7	<2.0
NDL-100	30.0	60.0	60.0
EC2312A	30.0		5.0
Paranox	30.0	40.0	60.0
Parasol II	13.0	60.0	<40.0
Parasurf	40.0	70.0	60.0
Para Clear, D500	10.0	60.0	60.0
Pro Sperse	40.0	70.0	60.0
Pro Loss	30.0	60.0	60.0
Emul-Break	10.0	5.0	60.0
Superior Well Xylene	30.0	0.9	90.0
Barsol Xylene	30.0	1.0	60.0
Valley Solvents Xylene	30.0	10.0	100.0
Weatherford PC2, Xylene	30.0		90.0
SCS P762	25.0	5.0	10.0
StimSol	13.0		70.0
Mil-break, 943	7.0	25.0	
Halliburton Xylene	20.0		83.0
Paragon	30.0		100.0
N-Ver-SperseO*	30.0		90.0
Barsol D100	5.0		10.0
DWP 931	5.0		13.0

Source: Schaeffer and Bernhardt, 2014, with data from EPA Material Safety Datasheets and FracFocus.org

Leading Technologies and Practices to Mitigate Impacts
Leading technologies and practices to minimize the risk of surface water contamination will be presented in this section. Recommendations and examples of states

implementing these practices will be covered for (1) recycling and reuse, (2) storage, (3) treatment and disposal, and (4) residuals management. Finally, recommendations for key contaminants in hydraulic fracturing wastewater will be covered.

Leading management practices for hydraulic fracturing wastewater should focus on minimizing risks to surface waters. First, recycling and reuse are key to reducing the overall volume of wastewater requiring disposal. Second, proper storage, treatment, and disposal, including disposal of residuals, reduce the impact of the key wastewater contaminants.

Leading management practices for hydraulic fracturing wastewater should first promote minimizing discharges to surface waters through recycling and reuse, particularly on-site to reduce transport. As mentioned previously in this report, **Texas** recently implemented regulations to encourage recycling and reuse of hydraulic fracturing wastewater (GWPC, 2014). Also, on-site treatment for recycling and reuse benefits from innovations in modular and portable treatment units, such as Aquatech's MoVap Shale Gas Wastewater Mobile Distillation Unit that has been used in **Pennsylvania**'s Marcellus Shale.

Implementing leading management practices for storage can reduce the risk of leaks and spills contaminating surface waters. While the number of storage tanks has been increasing, pits are still the most common type of storage across the oil & gas industry (GWPC, 2014). There are trade-offs in risks between storage pits and tanks. Pits may overflow or leak causing part of the stored liquid to flow to surface water bodies or infiltrate into the ground. Tanks may also leak part of their stored liquid similar to pits, but they are uniquely at risk for catastrophic failure where the entire contents of the tank are emptied at once, leading to surface flow or infiltration. Storage pits are open to the environment, rendering them vulnerable to overflow during rainfall and snowmelt, illegal dumping and vandalism, and potentially harmful interactions with wildlife. Tanks provide a closed system of storage with easier maintenance and leak detection. Pits provide larger volumes of storage at a lower cost than tanks, but have a higher risk of shallow groundwater contamination due to being dug into the ground (GWPC, 2014).

Risks related to storage pits can be reduced with proper regulations. Important regulatory measures include instituting competency standards for pit liners (required by 23 states), requiring freeboard or extra pit wall height above fluid level to allow for rise during rainfall and snowmelt events (required by 20 states), and conducting pre-operation inspections (required by 10 states), based on a review of 27 states (GWPC, 2014). For example, **Pennsylvania** requires pit liners to have a minimum thickness of 30 mils as well as sealed seams, while both **Pennsylvania** and **Colorado** regulate a minimum freeboard requirement of 2 feet at all times (GAO, 2012).

Storage tank regulations are also important for minimizing risks. To protect against catastrophic failure and leaks, 23 of the 27 states reviewed had implemented secondary containment, such as dikes, which provide an area of extra storage surrounding the tank that can collect up to 100% of the stored fluid during an accident (GWPC, 2014). Tank design requirements have also been specified in five states, with **Colorado** specifically implementing standards from Underwriters Laboratories and API (GWPC, 2014). However, more states can improve requirements concerning specific tank building materials that are resistant to corrosion, as well as requiring leak detection and inspection schedules.

Some states are encouraging the transition from storage pits to tanks by limiting the conditions under which pits may be used. For example, **North Dakota** passed a new law that may reduce the number of pits by mandating that pits used to store flowback fluid must be drained and the pit reclaimed within 72 hours after completion of hydraulic fracturing (GAO, 2012). **Colorado** requires tanks when operations occur within some drinking water supply areas, while **Wyoming** requires tanks when shallow groundwater occurs (less than 20 feet below surface) (GAO, 2012).

After maximizing recycling and reuse, best management practices should focus on contaminant treatment and appropriate disposal. In surface water systems, wastewater and drinking water are inextricably linked. If a contaminant is not handled by wastewater treatment, it can end up in surface waters, which are inputs to drinking water facilities. As such, since POTWs are not designed to handle high TDS loads, disposal of hydraulic fracturing wastewater at POTWs should be banned and informal moratoriums such as the one imposed by the PADEP should be formalized. Three states have already banned disposal to POTWs and five states do not allow it under their current policy but have no formal regulations (GWPC, 2014).

Upgraded CWTs for treatment and disposal are a new and promising option for states to minimize surface water impacts. By re-permitting the facilities under NPDES to accept hydraulic fracturing wastewater and completion of appropriate treatment process upgrades to remove dissolved salts, hydraulic fracturing wastewater can be treated, monitored, and disposed at centralized facilities that are subject to oversight. Additional state regulations for specific contaminants could address regulatory gaps created by federal exemptions, as well as manage particular contaminants that are relevant to each state. At this time, NPDES permits to accept hydraulic fracturing wastewater and dispose of it to surface waters have only been issued to a few CWTs (GWPC, 2014), but this approach holds great potential.

Thermal distillation treatment is a promising treatment process to upgrade CWTs. Thermal distillation can remove nearly all dissolved salts in hydraulic fracturing wastewater (Harkness et al., 2015), reducing the TDS load to below the recommended 500 mg/L and rendering it safe for surface water disposal. In **Pennsylvania**, two CWTs have been upgraded to remove dissolved salts with a unique form of thermal distillation, called AltelaRain, that includes a internal heat transfer process to reuse waste heat and lower energy costs. Compared to traditional thermal distillation, this process produces four times the distilled water per unit energy input (Boschee, 2014). A pilot demonstration of this process estimated the cost to be $5.29/barrel, representing a 16% savings over conventional transport and disposal costs, but the authors note that savings are probably even higher at the actual large-scale plants (Bruff & Jikich, 2011).

When discussing any type of wastewater treatment, it is important to note that treatment processes remove contaminants from wastewater, but that the contaminants themselves are still present and now concentrated in residuals, such as side stream, brines, and sludge. Therefore, proper handling and disposal of residuals, particularly those with NORMs (discussed in subsequent section), is as important as adequate treatment (Crittenden et al., 2012; GWPC, 2014).

A best management practice for disposal of solid residuals is landfilling, provided they meet disposal requirements. Liquid residuals are sometimes sent to other treatment facilities, which may not have TDS discharge limits or inadequate treatment technology. The liquid residuals are essentially diluted before release into surface waters, effectively negating the original treatment of the hydraulic fracturing wastewater. States should consider the whole treatment cycle of hydraulic fracturing wastewater and require the disposal of liquid residuals at Class II UIC deep injection wells (Hammer, 2012). Specific risks from key contaminants can be addressed by the following leading management practices:

Total Dissolved Solids

Recycling and reuse of wastewater for further hydraulic fracturing should be maximized to limit introducing TDS to surface waters, yet TDS is one of the main roadblocks to recycling by increasing friction during the hydraulic fracturing process. Thermal distillation, membrane desalination, or blending with freshwater can be used to lower the TDS to acceptable levels for reuse. Recent innovations in high-salinity tolerant friction reducers are also increasing acceptable TDS limits and lowering barriers to reuse (Mauter and Palmer, 2014). One pilot study in Canada found similar shale play performance between high TDS water treated with high-salinity friction reducers and freshwater treated with typical friction reducers (Paktinat, 2011; Boschee, 2014).

Once recycling and reuse is maximized, some high TDS hydraulic fracturing wastewater may remain that requires disposal. A preferred treatment method is thermal distillation, because it can remove extremely high levels of dissolved solids and new technologies have reduced the typically high energy inputs required (Hammer et al., 2012; Veil, 2010; Vengosh et al., 2014). Desalination by membrane processes, such as reverse osmosis, can treat moderately high levels of TDS, but requires high energy inputs as it is a pressure-driven process (Crittenden et al., 2012). Forward osmosis, which pulls freshwater from wastewater using a draw solution, has been gaining attention as an alternative to pressure-driven membrane processes for the treatment of highly saline hydraulic fracturing wastewaters (Cath et al., 2006; Coday and Cath, 2014; Hickenbottom et al., 2013).

Industrial additives (BTEX)

Only diesel-based additives are subject to UIC permitting, even though unregulated non-diesel additives may contain higher levels of BTEX. States could consider mandating industry disclosure of BTEX levels in additives or regulating all BTEX-containing additives to fill the UIC gap. In **Wyoming**, the use of BTEX compounds in hydraulic fracturing of hydrocarbon bearing zones requires prior authorization from state regulators, and injection into groundwater is prohibited (GAO, 2012). BTEX can be removed from wastewater with various treatment methods, including adsorption and membrane filtration (Hammer et al., 2012; Igunnu & Chen, 2012).

Radionuclides

First, NORMs can be removed from hydraulic fracturing wastewater through a variety of treatment processes, including sulfate precipitation, lime softening, ion exchange, and reverse osmosis (Hammer et al., 2012). States should assess whether NPDES permits for surface water disposal need to limit radioactivity, as levels vary with subsurface geology. More stringent permits would encourage upgrades in treatment and testing protocols, or alternate disposal methods. For example, in **Wyoming**, many NPDES permits for direct discharges to surface waters limit radioactivity, causing operators to send contaminated water to Class II UIC deep injection wells instead (GAO, 2012).

During treatment, NORMs are concentrated in solid residuals, such as sludge, and liquid residuals, such as brines. There are no federal regulations specifically governing the testing of radionuclides in treatment residuals nor their disposal, yet general solid waste disposal regulations apply (EPA, 2005; EPA, 2014e). Therefore, it falls to states to regulate proper testing and appropriate disposal methods of radionuclide-containing residuals.

Solid residuals are often landfilled. For municipal landfills, some states, such as **Pennsylvania**, require monitoring of radioactivity levels of incoming solid wastes, but typically measure gamma radiation alone, which only roughly estimates particular radionuclide levels (Zhang et al., 2014). States should consider more comprehensive testing protocols, and directing higher radioactivity residuals to other disposal sites, such as low-level radioactive waste (LLRW) landfills or hazardous waste (RCRA Subtitle C) landfills (EPA, 2005).

Liquid residuals are often disposed of in deep injection wells. However, NORM-containing wastes from hydraulic fracturing are exempt from federal hazardous waste regulations of Subtitle C of the Resource Conservation and Recovery Act and are designated "special wastes", instead of radioactive wastes (Rich and Crosby, 2013). Due to this exemption, they may be disposed of in Class II deep injection wells, instead of the more stringent Class I wells that are specifically designed for radioactive wastes (Hammer et al., 2012). Since states often administer their own UIC programs governing deep injection wells, there is an opportunity for states to pursue more rigorous testing and disposal regulations for deep injection wells to accept residuals with radioactivity.

Disinfection byproducts

Due to the toxicity of these contaminants and their ability to disrupt drinking water treatment plants, disinfection byproduct precursors, including iodide and bromide, should be removed in the wastewater phase, before they are introduced into surface water drinking supplies. Treatment processes include thermal distillation, electrochemical processes, and membrane filtration (Hammer et al., 2012).

Recommendations:

Overall, states can play an important role in protecting surface waters from hydraulic fracturing wastewater contamination. Key recommendations for states to consider include:

- Maximize reuse and recycling of hydraulic fracturing wastewater by leveraging on-site treatment innovations to reduce transport, as well as implementing regulations that foster reuse and recycling by allowing permit-free transfers of wastewater between operators.
- Implement best management practices for storage to minimize risks of leaks and spills. Pits, which are currently the most common form of storage, should be required to have pit liners and freeboard, or states may want to encourage a transition to tank storage. Tanks should be required to have secondary containment and corrosion-resistant building materials. Leak detection systems and inspections are crucial for both types of storage.
- Implement best management practices for wastewater treatment to minimize surface water contamination risks. Disposal to POTWs should be banned. All wastewater treatment could occur at CWTs with proper treatment upgrades, in order to provide centralized oversight of treatment and surface water disposal of hydraulic fracturing wastewater. States could also institute new regulations for CWTs for specific contaminants to address regulatory gaps created by federal exemptions, such as BTEX, as well as manage particular contaminants that are relevant to each state.
- Proper handling and disposal of residuals, where contaminants are concentrated during treatment, is equally important as treatment itself. States should consider the whole lifecycle of the contaminants to avoid negating the benefits of wastewater treatment and re-introducing contaminants to surface waters through improper disposal.

CHAPTER 4: DESIGN AND IMPLEMENTATION OF STATE-LEVEL POLICY TO ADDRESS IMPACTS OF UNCONVENTIONAL ENERGY DEVELOPMENT AND DISTRIBUTION

There are several basic policy approaches that states can use to mitigate the impacts of unconventional oil and gas development and distribution. Overall, these policies have two goals: 1) to encourage firms to invest in measures that reduce the risks inherent to oil and gas production, and 2) to ensure there will be resources to mitigate the effect and fully compensate those hurt if damage occurs. Our research examines the benefits of performance-based standards and provides recommendations for ways to use market-based approaches such as mandatory insurance and taxes, or a liability approach such as trust funds. **A state should review their statutes regarding natural resource regulation and permitting, for gaps, loopholes, or ambiguous definitions, to determine if the state needs further regulation to address the impacts on air and water of unconventional oil and gas development and distribution.** This chapter discusses the needs, challenges, and successful approaches to incorporating three key elements to strengthen the design of effective policy in this area. The three elements include: engagement of key stakeholders through collaboration and coordination, adaptive management, and monitoring and enforcement.

Engagement of Key Stakeholders

Needs

Strong communication and engagement of all stakeholders is vital to the political feasibility of responsible unconventional oil and gas development. In order to create comprehensive and effective policy, states must actively engage stakeholders including industry, environmental and advocacy groups, as well as local communities. The state has an important role to serve as a mediator, cultivating trust among, and encouraging active involvement of, key stakeholders to continuously improve the management of risks connected with unconventional oil and gas development and distribution in their state.

Challenges

While many of the impacts of oil and gas development are similar for unconventional and conventional oil and gas, unconventional development has greatly increased the number of wells being drilled in the United States. To effectively exploit the resource requires a large number of wells to be drilled on an ongoing basis, due to the lower permeability rock and more rapidly declining production rates than exist for conventional oil and gas. In addition, some unconventional oil and gas plays underlie existing urban and suburban areas, resulting in a greater interface between communities and industry than previously existed in many of these areas. As a result of drilling and production directly impacting a greater portion of the population, new tensions between industry, environmental groups, local communities, and different levels of government can result.

As oil and gas development grows, so does constituent pressure on local authorities for increased protection from the impacts of drilling in their communities (Minor, 2014). While local governments generally have zoning authority that allow them to circumscribe where heavy industrial activity can occur, this authority is usually quite limited when it comes to oil and gas drilling and production, reducing local governments' ability to indirectly influence the industry's activities through zoning rules (Center for Western Priorities, p.3, 2014). At the same time, there are significant exemptions from federal regulations for the oil and gas industry, and regulations at both state and federal levels often lag behind the rapidly changing technology and practices in the industry. These factors contribute to public fear that current federal and state laws fail to cover the negative impacts of oil and gas development in communities. In this context, mounting pressure from constituents on local authorities causes friction between local and state governments over regulatory authority (Small et al., 2014). Many local governments have reacted by trying to ban, either effectively or outright, the use of hydraulic fracturing in their jurisdictions, including Morgantown, **West Virginia** (Cir. Ct. Monongalia Cnty., Aug. 12, 2011); Boulder, Broomfield, Fort Collins, Lafayette, Longmont, **Colorado** (Soape & Strahn, 2014); and Denton, **Texas** (Malewitz, 2014). This struggle over control pits state governments against local governments and results in expensive, drawn-out lawsuits (Minor, 2014).

The state government has to balance local flexibility to tailor regulations with the need to design cost-effective regulations. There is also the possibility of disagreement among industry players. Many operators and service companies voluntarily operate at a higher standard than regulations mandate, and when other operators do not work at that standard it not only harms the economic competitiveness of responsible firms, but also increases the risk of accidents that will damage all industry players' reputations (Small et al., 2014). Industry leaders discuss the priority they give maintaining their "social license to operate" through acting in a responsible way that eases public concerns and earns rapport within the communities where they operate (Liroff, 2013). According to one wastewater management operator, for example, many in his state already comply with much higher standards than what is required by both federal and state law for wastewater storage and storm water protection because the operators who contract them require it and because it is "the right way to work". While an array of issues fuel public distrust, it is important for both government and leading environmental groups to acknowledge significant differences among industry players and to actively engage with responsible firms to help address the state's needs.

Successful approaches

The state can help foster productive communication among stakeholders by serving as a mediator and organizing collaborative efforts engaging groups at various levels throughout the process. As a mediator the governor and state regulators help to resolve disagreements, cultivate trust, and encourage various communication channels among stakeholders to reduce polarization. It is important for government to acknowledge the significant heterogeneity across firms' operating standards and to engage closely with leading, responsible operators to augment trust and communication among industry, environmental and advocacy groups, and local governments. We recommend that governors and state regulators assemble task forces comprised of leading industry members and environmental groups to inform policy development from the beginning, and take ownership of the policy. A few conditions are important when picking the leading groups to come to the smaller table:

- In order to formulate successful policy, stakeholders must first be able to acknowledge the importance of governance (Rahm & Riha, 2014). Representatives from industry need to acknowledge public concerns and be open to dialogue with environmental groups to best mitigate the concerns and regional risks. Leaders in industry stress that they believe in regulation of the industry, but they want smart and effective regulation. *Industry representatives need to acknowledge the risks associated with oil and gas development and engage in an open conversation with advocacy groups and communities.* In turn, environmental groups at the table need to not see the industry as their adversary, but rather have a pragmatic outlook on how to develop energy in the state as safely as possible.
- Second, stakeholders and policy makers must be able to discuss and roughly agree on the risks or issues they are going to address at the beginning of the process, and third, they must be willing to explore multiple management and regulatory options (Rahm & Riha, 2014). The working relationship with both industry and environmental groups at the table needs to be such that if one side thinks a proposed policy will not work, they come with an alternative approach to try to make a compromise.

State governments must work with leaders in industry to create clear, high performance standards. Numerous operators voluntarily abide by standards demanded by operators that are above EPA or state regulations. States do not need to reinvent the wheel when seeking to develop strong regulations to mitigate risks in their region. States could turn to the State Review of Oil & Natural Gas Environmental Regulations (STRONGER) guidelines that outline best practices to prevent accidents and pollution. Such guidelines have a commitment to high standards of safety and environmental performance. **Box 2** provides a partial list of organizations that have developed high performance standards.

A Local Governmental Designee (LGD) Program, like that in **Colorado**, is a way to improve communication channels between the state regulatory agency and local governments and communities. A LGD is typically a member of a municipality's planning staff and their level of participation varies based on the municipality's interest. As the primary contact point between state regulatory agency and the local government, LGDs have specific rights and opportunities to participate in state permitting, hearings, enforcement actions, and other processes. The state regulatory agency should dedicate a number of staff members whose full-time jobs are to provide outreach, training, and support tools to the LGDs.

Operator Licensing Agreements can also help provide local control and flexibility to adapt plans to minimize impacts and concerns in specific areas, without increasing statewide regulatory complexity. Local government can use these agreements if they decide that they want best management practices by operators to go beyond the state regulatory rule requirements. If the operator and municipality can agree to these extra parameters, they sign a contract to that effect. If the local government and operator cannot come to an agreement on additional contractual points that local government wants, then a rule goes to the state regulatory agency's Committee for a vote that has to be open to public comment. Such a system may incentivize companies to agree to Individual Operator

Box 2: Organizations and Associations with Leading Practices

The State Review of Oil & Natural Gas Environmental Regulations (STRONGER) is a non-profit corporation that educates regulators and the public on appropriate elements of a state oil and gas regulatory program. STRONGER compares various state programs against the guidelines they have developed.

The Interstate Oil and Gas Compact Commission (IOGCC) advocates for member states' rights to govern petroleum resources to efficiently maximize the benefits while protecting health, safety, and the environment through sound regulatory practices. The IOGCC accepts the STRONGER guidelines for the protection of health, safety and the environment.

The American Petroleum Institute (API), which publishes standards, recommended practices, guidance documents and technical reports covering many aspects of the oil and gas industry, including specific documents for unconventional development, that are often referenced by state regulations.

The Center for Sustainable Shale Development (CSSD), a collaboration between shale gas production companies and environmental non-government organizations, has created a set of performance standards aimed at protecting the environment. The CSSD recently established a protocol for compliance monitoring and certification, to be conducted by an independent third party.

The Groundwater Protection Council (GWPC) has published a report "State oil and gas regulations designed to protect water resources" comparing regulations in the 27 most important oil and gas producing states, with 2009 and 2014 editions. The most recent report captures the state of regulations as of July 1, 2013.

The Environmental Council of the States, through its Shale Gas Caucus, seeks to promote coordination and sharing of leading practices, and is currently focusing on their "Project to Promote Interstate Coordination on Methane and VOC Emissions."

Licensing Agreements with communities rather than risk something being codified into an actual rule statewide. Before others adopt such a system, however, states should conduct further research on its effectiveness.

In addition to engaging key stakeholders, states are examining ways to further ease public concern. In **Louisiana**, for example, to address public concerns about impacts on water supplies communities receive advance notice of O&G development (Ceres, 2014). **Louisiana**'s system of disclosure allows local policymakers to feel more control in managing the development and mitigating risks to their communities (Ceres, 2014). To help address public transparency concerns, **Pennsylvania** developed the Susquehanna River Basin Commission's Water Resource Portal to disclose water permits and data on amounts and location of withdrawals to the public (Ceres, 2014).

Adaptive Management

Need

State regulators need to have both willingness and a mechanism for adapting and revising options in the face of new information. Mechanisms for responding to new research and data, adopting policy revisions and changes to practices, in a timely and appropriate manner is key in an ever-evolving landscape for shale energy development (Rahm & Riha, 2014).

Challenges

Industry leading practices constantly evolve with new research and technological innovation. "Best practices" in unconventional oil and gas development operations greatly vary depending on the geography, geology, and hydrology of an area. What works in one region may not be necessary or, alternatively, may not be sufficient to protect the environment in another area (Nolon, 2013).

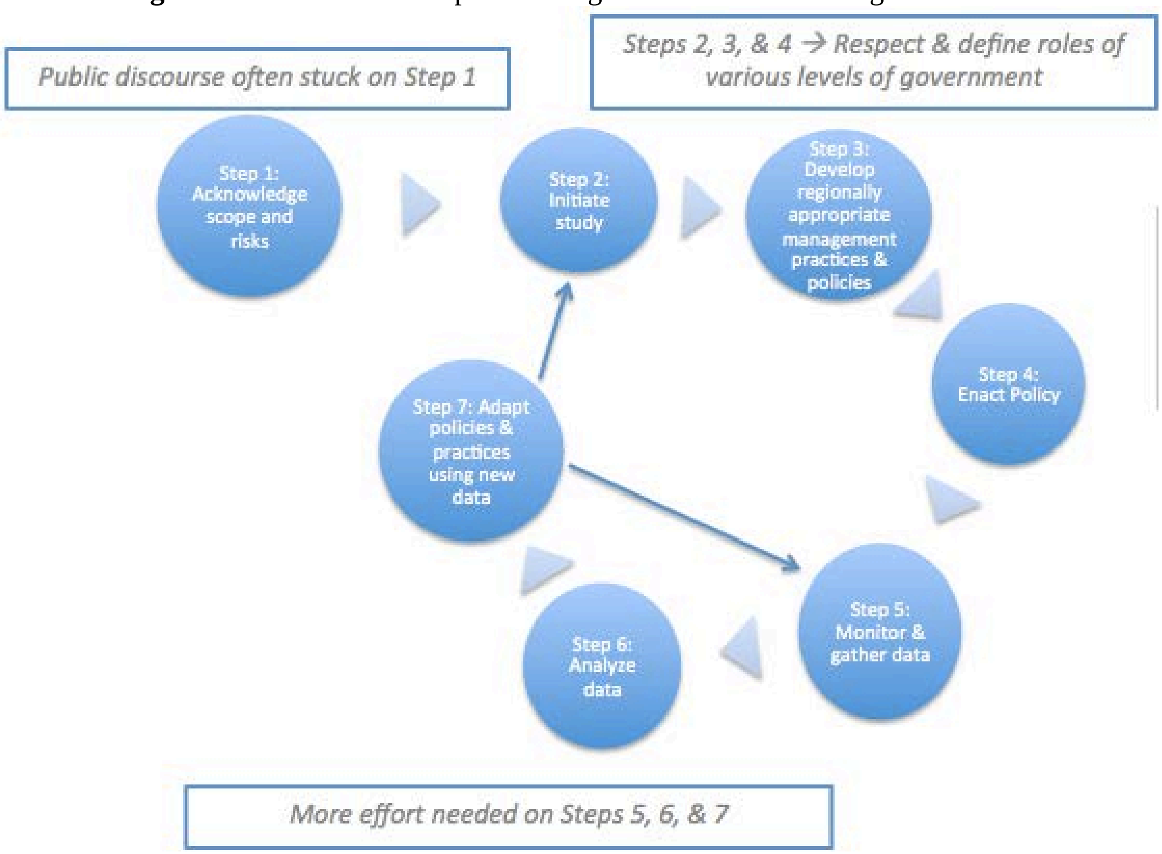
Successful approaches
State-level regulations that require operators to use specific measures to mitigate routine impacts and reduce the risk of accidents must account for differences in how oil and gas are extracted and treated in different parts of the state. Regulators can build more flexibility into their rules by setting performance standards that set minimum objectives for firm activity and give firms the flexibility to meet these goals in the most efficient way. Market-based approaches —such as taxing the value of natural gas firms vent or flare, or requiring insurance that makes firms pay higher premiums when they take on more risk— increases flexibility further by allowing firms to decide what level to strive for and how to get there. These tools can also create incentive systems for industry to continually improve their technology and practices in order to reduce costs along with environmental risks. All of these approaches, however, must be revisited regularly as technology, industry practices, and community priorities change.

Using an adaptive management decision-making process can help governments and stakeholders address complex environmental issues in a way that reduces polarization of important discussions on risk. In addition, this framework can help states mitigate immediate and long-term impacts of unconventional oil and gas development (Rahm & Riha, 2014). Adaptive Management includes:

1) Identification of the scope of potential risks involved in unconventional energy development
2) Initiation of studies to gather the data needed to assess such risks and baseline data for future monitoring
3) Development of regionally appropriate management policies and practices applicable to unconventional energy development activities in the state
4) Enactment of policies
5) Monitoring and recording data of impacts
6) Analyzing data
7) Adapting policies and practices using new data
8) Return to #2 and #5 to evaluate risks and impacts of the new policies.

As the flowchart in **Figure 7** shows, policy makers then go back to Step #2 for further study to refine new policies and practices and to Step #5 to monitor the effectiveness of recently adapted policies and practices. In order to identify

Figure 7: Schematic of Adaptive Management Decision Making Process



Source: Adapted from Rahm & Riha, 2014.

mitigation options that reduce multiple or cumulative risks, states need to coordinate regulatory bodies through central planning (Small et al., 2014). According to states further along in the unconventional oil and gas development process, the future is in central planning. This includes encouraging operators to coordinate drilling sites, construction of natural gas gathering lines, and use of centralized storage to increase efficiency from wellheads. Using economies of scale will reduce emissions, truck traffic, etc. Both operator licensing agreements and Local Governmental Designee Programs are tools to help with central planning in municipalities, supported and connected to the state regulatory agency for technical support. These tools have the potential, along with important use of technology advances using GIS mapping tools, to: maximize the use of existing infrastructure, reduce land surface disturbance, avoid sensitive areas, and minimize cumulative effects in an area (Small et al, 2014). In addition it enables a higher degree of community and stakeholder participation in the site selection and implementation of drilling. **Table 3** presents a partial list of approaches to central planning used in different jurisdictions to manage the oil and gas industry.

<u>Monitoring and Enforcement</u>

Need

States must have the authority, means, and capacity to monitor and evaluate the effectiveness of management and regulatory options once they choose (Rahm & Riha, 2014).

Challenges

Having strong laws on the books is only part of improving practices. States often lack the personnel and expertise to ensure effective oversight (Small et al, 2014). It takes time to build a team of inspectors with these skills, and retaining them requires salaries commensurate with what industry offers. Where inspectors are too few or lack the skills to ensure rules are followed, companies can cut corners with impunity (Schumacher & Morrissey, 2013, p. 249). This is true for all regulatory approaches; inspectors must verify mandated measures are implemented, monitor impacts to ensure performance standards are met, and measure outcomes important to market-based regulation. Performance standards and market-based regulation require some measurable outcome that can be attributed to a firm. This makes them useful for limiting routine impacts, but inappropriate for managing the risk of accidents, since inspectors cannot directly measure risk.

Approaches that require minimal regular monitoring and evaluation have their own problems. The threat of civil suits for damages encourage firms to reduce risks and does not depend on widespread state-sponsored inspections since plaintiffs come forward on their own account, but suits are expensive and slow, outcomes are uncertain, and operators may not be able to pay for their liabilities. If operators think the odds of paying large damages in the event of an accident are small, the tort process does little to incentivize good behavior. Moreover, small companies may not invest enough in safety since they know that if something goes wrong they will go bankrupt and not pay for the damage in full. Indeed, a recent study found a **Texan** policy designed to make firms internalize the risk

Table 3: Examples of Adaptive Management and Central Planning in Oil and Gas Management

Authority	Use of Adaptive Management Elements and Central Planning
Colorado	Requires gas operators to propose a Comprehensive Drilling Plan for multiple drilling locations
Illinois	Legislation enacted in 2013 include elements of a Comprehensive Development Plan
Maryland	Proposed a mandatory Comprehensive Gas Development Plan from the operator prior to receiving a permit to drill. The plan must specify the locations of all planned well pads, roads, pipelines and supporting facilities over a period of five years and comply with all land use, location, and setback regulations. In addition, resource monitoring and characterization is required prior to drilling to provide a baseline for impact assessment (Small et al, 2014).
Pennsylvania	Requires a water management plan for shale gas production that covers the full lifecycle of water, including identification of the water source, the amount wanting to withdrawal, and an analysis of the withdrawal impact on the source (Richardson et al., 2013). **Pennsylvania** also established a statewide database for wastewater management information.
Quebec, Canada	Regional Strategic Environmental Assessment to “inform the preparation of a preferred development strategy and environmental management frameworks’ regarding shale gas” (Rahm & Riha, 2014)
European Union	Using a Strategic Environmental Assessment to formulate region-appropriate plans and policies

of bankruptcy from environmental liabilities significantly reduced small companies' role in unconventional oil and gas extraction, suggesting these companies were explicitly basing production decisions on the fact they would not bear the full cost of large accidents (Boomhower, 2014). Mandated insurance, which seem attractive because insurers raise premiums on companies they perceive as operating in risky ways, requires insurers to understand what determines risk and to do their own monitoring in setting premiums. These are capabilities large insurers still lack (Reddall & Berkowitz, 2012).

Successful approaches

States need to allocate sufficient funding to responsibly enforce and monitor laws and regulations. For regulations concerning water contamination to be effective, states need to fund planners and scientists to conduct the necessary research before oil and gas development begins in order to obtain baseline data to assess the connection, if any, between industry actions and impacts on water quality (Schumacher & Morrissey, 2013). Successful regulatory regimes emphasize continual data collection to constantly monitor the risks and impacts of shale gas development before activity even begins (Rahm & Riha, 2014).

Penalty fines must be sufficiently high to effectively deter violations. For example, **Colorado** recently used executive order to implement HB 14-1356, a statute to codify higher penalty for violations going from $1,000 fine per day per violation with a cap of $10,000 per violation to now fine up to $15,000 per day and no cap (Svaldi, 2015). In addition to increased fines previously mentioned (for air page 16 and water page 25) problems arise with state regulatory bodies waiving fines. **Colorado's** COGCC voted in January 2015 to limit the director of the commission's ability to waive all penalties in "serious cases" (Svaldi, 2015). Other states may consider removing their regulatory bodies' abilities to waive fines.

To improve the efficiency of inspections regulatory agencies may consider implementing a risk-based calculation system to determine the order of wells to inspect. This calculation includes information such as well location, violation history, and date of last inspection (Reynolds, 1995).

From the beginning states should institute an electronic permitting system for oil and gas leases in order to streamline data collection and monitoring and evaluation. Some states still have paper permitting systems. State governments can help establish interstate compacts and commissions to coordinate management of water, air, and other ecological resources with neighboring states especially for well pads located near state borders (Small et al., 2014). For example: The Susquehanna River Basin Commission, a federal interstate compact responsible for managing the basin's water resources, regulates all water withdrawals from the basin, including for shale gas development (Small et al., 2014).

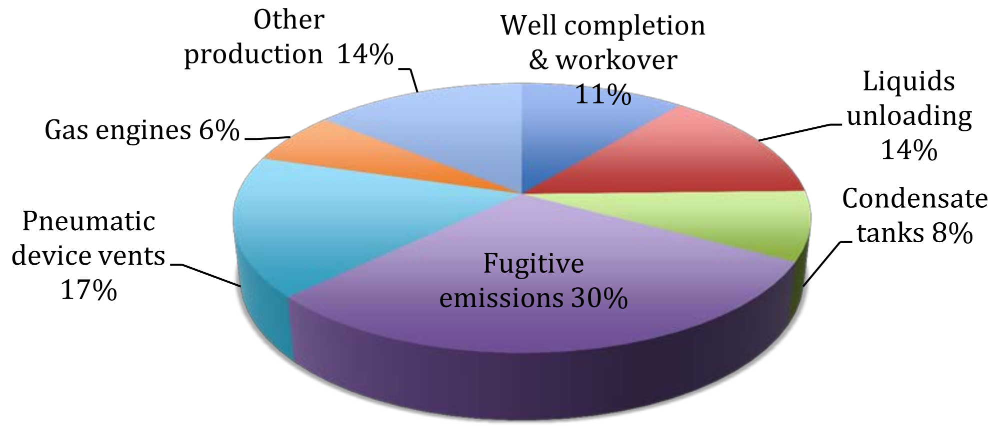
State governments have multiple tools at their disposal to improve the effectiveness of using tort law. Baseline data helps both sides protect themselves against spurious claims. Since plaintiffs have to prove drilling caused contamination, resolving ambiguity with baseline data disproportionately helps plaintiffs. Many states require well operators to test freshwater wells within a certain distance of proposed wells for contaminants before drilling begins (Richardson et al., 2013, pp. 29–30), which helps courts determine whether pollution found after drilling was caused by drilling or predates it. **Pennsylvania** has taken the idea of using the tort process further: instead of requiring testing, state law holds that operators can only argue contamination predates drilling in water wells within 2,500 feet of a well if they did a baseline test to prove it. Richardson et al. (2013) describe this as a "burden-shifting rule," transferring the burden of proving whether contaminants predate drilling from plaintiffs (who would normally have to show it did not) to defendants (who now must prove it did). Burden-shifting rules can encourage operators to employ risk-reducing measures without forcing them to do so at wells where it is impractical or does little to reduce risk.

Conclusion

This report outlines an array of policy recommendations that states can consider for reducing the impacts of gaseous emissions and water contamination from unconventional oil and gas development. State-level policy can encourage responsible development of the industry by **engaging key stakeholders**, continually improving the comprehensiveness of state regulations as technology and research evolves by **developing an adaptive framework**, and increasing effectiveness of **monitoring and enforcement**. The focus these approaches put on the processes of developing and enforcing regulation are as important to the long-term safety and public acceptance of unconventional oil and gas production as the content of extant regulations.

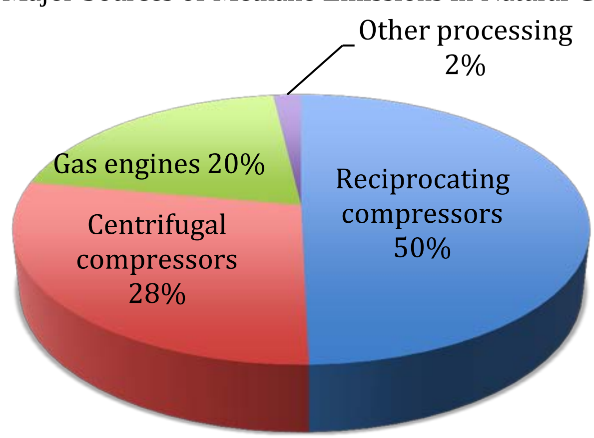
APPENDIX: ADDITIONAL METHANE EMISSION FIGURES

Figure A1: Major Sources of Methane Emissions in Natural Gas Production



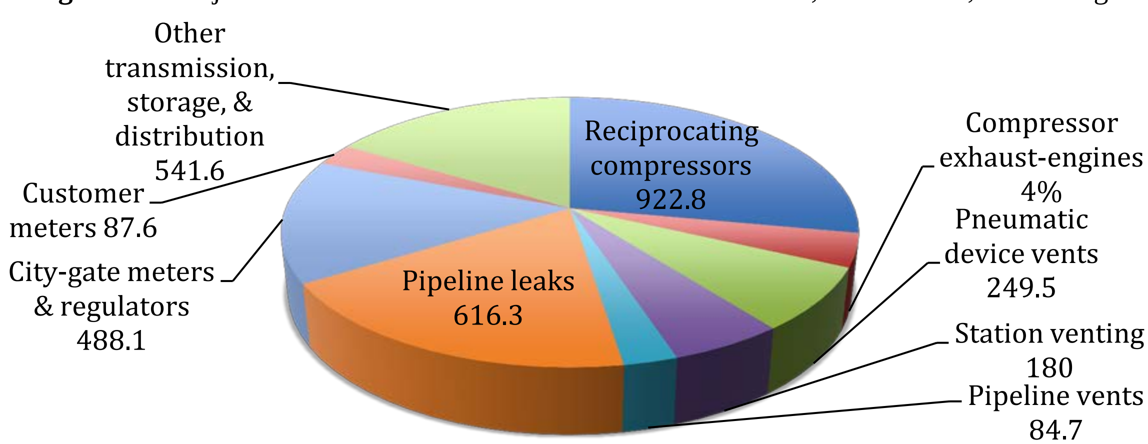
Data Source: EPA, 2014a

Figure A2: Major Sources of Methane Emissions in Natural Gas Processing



Data Source: EPA, 2014a

Figure A3: Major Sources of Methane Emissions in Transmission, Distribution, and Storage



Data Source: EPA, 2014a

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