

Hydraulic Fracturing in North Carolina: Analysis of Draft Regulations to Inform the
Environmental, Public Health, and Economic Implications of an Unconventional Oil and
Gas Industry in the State

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Part 1: Introduction to Fracking and Relevant Background Information

Introduction and Scope

The purpose of this thesis is to provide an in-depth analysis of North Carolina's proposed rule set for hydraulic fracturing to discover the future environmental, public health, and economic implications of an unconventional oil and gas industry in the state. While nevertheless important to the people and communities of North Carolina, the social implications of an unconventional oil and gas industry are outside the scope of this paper. For example, issues such as forced pooling, noise/light pollution, and criminal penalties for unauthorized disclosure of trade secret information are intentionally excluded from the paper's discussion and analysis of regulations. Part 1 begins with background information that should establish a sufficient foundational knowledge of hydraulic fracturing, the regulatory landscape at the federal level, and the framework within which North Carolina's rules were drafted. Part 2 discusses state-level regulation of hydraulic fracturing, introducing North Carolina's rule proposals for each area of regulation, using the Marcellus Shale states as a case study, and considering perspectives of environmental groups and industry. Part 3 analyzes emerging best practices and key issues for fracking in North Carolina. Finally, policy recommendations are made.

Hydraulic Fracturing Background Information

Why Frack?

Since 1947, hydraulic fracturing (hereafter referred to as "fracking") has been used on over 2.5 million oil and gas wells worldwide and over 1.2 million wells in the United States (IPAA 2015). U.S. natural gas production has increased from 4,600,000 million cubic feet in 1947 to over 25,000,000 million cubic feet in 2012 (U.S. EIA 2015).

The U.S. Energy Information Administration (EIA) expects that the rate of fracking projects will continue to increase, as natural gas becomes a larger player in domestic energy production and consumption. In an EIA projection, “U.S. dry natural gas production increases 1.3 percent per year throughout the Reference case projection, outpacing domestic consumption by 2019 and spurring net exports of natural gas” (U.S. EIA 2013). Fracking makes possible the extraction of natural gas from many large reserves where extraction was previously uneconomical, technically infeasible, or both. Thanks to improvements in fracking technology, natural gas is now an abundant natural resource in the United States and the recent expansion of its production has driven prices down, making it cost competitive with competing fossil fuels—oil and coal.

Other than the abundant domestic supply, there are strategic, economic, and environmental benefits to fracking for natural gas. The White House’s 2011 “Blueprint for a Secure Energy Future” endorses the responsible development of America’s oil and natural gas resources, with the primary goal of reducing imports of fossil fuels (Majumdar 2012). For a variety of politically strategic reasons, America’s leaders have deemed it a priority to reduce the country’s dependence on foreign oil.

There are a number of economic reasons in favor of fracking. “*The Economist* predicts that by 2020 the fracking revolution “...should have added 2-4% to American GDP and created twice as many jobs than carmaking provides today” (The Economist 2014). The industry creates jobs for geologists, well drillers, truck drivers, construction workers, office workers, and many others (Gissen 2012). This job creation, in conjunction with royalty payments to property owners and tax revenues to the government, has the potential to provide a strong stimulus to local and state economies.

An April 2013 study “The Economic Potential from Developing North Carolina’s On-Shore and Off-Shore Energy Resources” conducted by N.C. State’s Dr. Michael Walden found the following benefits to be among those fracking would bring to North Carolina:

- Over a seven-year period, almost 500 jobs from infrastructure development and \$80 million in new annual income and
- Over a twenty-year period, almost 1500 jobs created from production activities and over \$150 million in new annual income (Walden 2013).

Although the above income and jobs numbers seem to signify a substantial economic boon, unconventional oil and gas is a boom-and-bust industry in which large-scale production and hence, large-scale revenue, tapers off quickly in the months and years following the fracking of a well; in reality, these economic benefits will likely prove to be relatively short-lived (King 2015). Furthermore, an unconventional oil and gas industry necessarily imposes a number of costs on states and localities, which can become externalities if not anticipated and accounted for by the regulatory framework (Goldman 2015). While a few decades of jobs associated with the oil and gas industry may provide a temporary economic stimulus, North Carolina only stands to benefit financially from fracking operations if the total taxes and fees collected from the oil and gas industry exceed the total costs created by the industry.

There are also some environmental factors in favor of developing natural gas resources. However, it’s important to note that these so-called ‘environmental benefits’ actually stem from the combustion of natural gas for energy production *after* it has already been removed from the ground and *not* from the fracking process itself.

Natural gas’s advantages over other [fossil] fuels include the following: it has fewer impurities, it is less chemically complex, and its combustion generally results in less

pollution. In most applications, using natural gas produces less of the following substances than oil or coal: carbon dioxide (CO₂), which is the primary greenhouse gas; sulfur dioxide, which is the primary precursor of acid rain; nitrogen oxides, which is the primary precursor of smog; and particulate matter, which can affect health and visibility (AGA 2015).

The use of modern fracking techniques “...has already driven down natural gas prices to the point where utilities are replacing dirty coal-fired power plants with cleaner natural gas-burning plants and increasingly vehicles are burning natural gas instead of dirtier gasoline” (Gissen 2012). As an energy source, natural gas will play an important role as the United States gradually shifts away from traditional fossil fuels and toward low-carbon energy sources. This is because many renewable energy sources are intermittent in their power production (e.g. solar panels at night, wind turbines on low-wind days) and natural gas power plants can quickly increase or reduce their power output in response in order to provide near-constant aggregate power production (IEA 2015). In this way, natural gas plants have an advantage over coal power plants; coal-burning power plants do not have this ability to quickly adjust their power output in response to the intermittency of other power sources.

Fracking Technology Timeline

Fracking was first used to extract natural gas from a well in 1947 (IPAA 2015). While the name “fracking” stuck, the process used today is much different than the process used in 1947. Mitchell Energy conducted the first modern fracking operation on the Barnett Shale in 1997 (Radix 2012). This operation used massive hydraulic fracturing also known as high-volume hydraulic fracturing, a technique named for the amount of fluid used by the process—an amount that dwarfs that of a traditional fracking job (Radix

2012). Mitchell Energy also used a cutting-edge slickwater frac on this well instead of the then-common gel frac; in fact, this was the first time the slickwater frac method was ever attempted (Radix 2012). Slickwater fracturing fluids are the kind used by today's fracking operations; the fluid is comprised of water, proppant, and chemical additives (Groundwater Protection Council [GPC] 2015b). Another key development since 1947 is the horizontal well, which has all but replaced the vertical well because it allows the operator to access much more of the shale play from a single well location (Bell 1993). A shale play is an underground rock formation that contains a significant amount of natural gas (U.S. EIA 2010). To construct a horizontal well, a vertical well is drilled first and then the horizontal portion of the well is drilled as an extension from the bottom of the vertical well that protrudes horizontally, far beneath the surface. The combination of massive hydraulic fracturing, slickwater fracking fluids, and horizontal wells is a more accurate depiction of today's natural gas extraction process. A brief, but more complete description of the current fracking process follows.

The Fracking Process

The fracking process allows for the extraction of unconventional mineral energy deposits that are characterized by a poor flow rate due to either low permeability of the rock formations in which they are contained or clogging of the rock formation during drilling (Daneshy 2010). First, a well is drilled, beginning with the vertical portion and then moving to the horizontal portion in the case of horizontal wells. Either three or four layers of steel casing, each perforated in key areas, are inserted into the well bore. The casing string—all of the casings together—includes conductor casing (only when necessary for additional structural support), surface casing, intermediate casing, and

production casing, which are in order of decreasing diameter (Richardson 2013). The casing layers are installed in this order. Cement is then circulated in the area between the layers of casing to hold them in place and prevent fluid from collecting between adjacent layers of casing. Now that the well construction is complete, a mixture called “fracking fluid” is pumped down into the well. When it flows through the casing perforations, the resulting pressure causes parts of the rock formation to fracture (U.S. EPA 2014b). These fractures release gas from the shale formation, and the gas flows through the well back up to the surface where it is collected. Some of the fracking fluid, called flowback, returns to the surface during and immediately after fracking the well (Schramm 2011). Produced water, originating from within the rock formation, flows back up to the surface gradually over the lifespan of the well (Schramm 2011). According to *ExploreShale.org*, the amount of fluid that remains underground accounts for anywhere from 70-90% of the total fracking fluid (Penn State Public Broadcasting [PSPB] 2014). Proppants, such as sand, are a part of the fracking fluid that is intended to remain underground to hold the fractures open (U.S. EPA 2014b).

Many of the environmental and public health issues associated with hydraulic fracturing stem from the composition of the fracturing mixture, particularly its chemical component. Industry is quick to point out that the mixture consists of 90% water and 9.5% proppant, leaving only 0.5% as chemicals (EFS 2013). Anti-fracking environmental groups cite 0.5% as the lower end of the spectrum, which, according to them, ranges from 0.5% to 2%, depending on the specific operation (Earthworks 2015). These chemicals serve a variety of purposes and may be divided into a number of classes, based on their purpose. These classes include acids, breakers, biocides, buffers, clay stabilizers,

corrosion inhibitors, cross-linkers, friction reducers, gelling agents, iron controllers, solvents, and surfactants (GPC 2015d). While 0.5% may seem insignificant *prima facie*, when this percentage is multiplied by the total amount of fracking fluid, the sheer volume of chemicals quickly becomes apparent. Horizontal shale gas wells require the largest amount of fracking mixture; a typical 4 million gallon fracking operation requires between 80 and 320 tons of chemicals (using *Earthworks*' more liberal estimate of chemical composition of the fluid) (Earthworks 2015). Many of the chemicals used are known to be toxic or carcinogenic to humans. After a fracking operation has been completed, some of the fracking fluid remains underground, unrecoverable, while the remainder resurfaces as flowback, picking up additional undesirable substances (such as salts, heavy metals, and radioactive elements) from below the Earth's surface (Haluszczak 2012). At the conclusion of the operation, flowback and produced water—collectively referred to as wastewater—must be disposed of. Finally, the operator must plug the well and reclaim all disturbed land associated with the operation; restoring it as near as possible to the condition it was in before construction and drilling activities began.

Following the fracking (or stimulation) of a well, the production rate of an oil or gas reservoir will decline over time (King 2015). The normal productive lifespan of an unconventional reservoir is 20-30 years (Allison 2014). “The decline is very rapid during the first year and [is] then followed by slower but continuous decreases” (King 2015). Decline rates are usually more rapid in unconventional oil and gas reservoirs than in conventional oil and gas wells reservoirs “...because of their ultralow permeability, limited reservoir contact, and the original completion strategy” (Allison 2014).

Performing a “workover” on a well, or refracturing it, is often done to combat production declines in unconventional oil and gas reservoirs in an attempt to extend the productivity of wells beyond their normal productive lifespan (Allison 2014). “Although refracturing seems an excellent method of significantly increasing gas production, only 15% to 20% of refractured wells achieve any desired improvement in practice” (Tavassoli 2013). In settings where “workovers” do in fact increase production rates, each additional refracturing treatment is still less effective than the previous “workover” if only because with time having elapsed (and production having continued), there is less oil or gas left in the reservoir.

Fracking Issues and Risks

The most significant environmental and public health issues associated with hydraulic fracturing include considerable fresh water consumption, air pollution, and the contamination of surface water and/or groundwater sources that can result from the disposal of wastewater (U.S. EPA 2014a). The EPA estimates that in 2011 alone, 35,000 fractured wells within the U.S. consumed 70-140 billion gallons of water (U.S. EPA 2011). Depending on the type of well, its depth, and location, a single horizontal well can use 3 to 12 million gallons of water for the initial fracking procedure (Breitling 2012; NETL 2009). Each time a well has a “workover,” a similar amount of water is required. The average shale gas well undergoes about 2 “workovers” during its lifespan to re-stimulate gas production (NETL 2010). The extraction of so much water in such a short time span can place stress on water supplies, especially in drought-prone areas. A recent study found that close to half of the nation’s fracked wells are located in areas of high or extremely high water stress (Freyman 2013). Water withdrawals must be managed and

coordinated effectively to avoid threatening local drinking water supplies and causing adverse ecological impacts to aquatic life and resources.

Air pollution manifests in the release of volatile organic compounds (VOCs), hazardous air pollutants (HAPs), particulate matter (PM), and greenhouse gases (most notably methane, but also SO₂ and NO_x) directly from fracking facilities and/or indirectly from activities associated with building the well site infrastructure and trucking materials to and from the site (NETL 2009; U.S. EPA 2014a). Some drilling areas have also experienced increases in particulate matter and ozone; this combination of air pollutants can lead to health problems including respiratory symptoms, cardiovascular disease, and cancer (U.S. EPA 2014f; U.S. EPA 2013). A study (funded 90% by industry and 10% by the EDC 2011) conducted by the University of Texas in 2013 found that methane emissions at the study sites were less than was initially feared (Borenstein 2013). However, critics of the study argue that the methane emissions levels observed in the study are a poor representation of the overall industry because the study included only 489 wells (0.1% of all natural gas wells in the U.S.) and these wells were likely best performers, particularly careful to limit methane leakage and volunteered by industry for that reason (Borenstein 2013; Romm 2013). "...The study authors say more research is needed to explain why some studies have found high rates of leaking methane and others have not" (Borenstein 2013).

Groundwater contamination and surface water contamination result from different aspects of the fracking process. Contamination of surface water usually results from aboveground spills or leaks, which are related to the management of land, chemicals, and wastewater (Goldman 2013). If chemicals are not handled properly, they can spill during

storage or transport. While there is no comprehensive study on the frequency of chemical spills, “hundreds of small leaks and spills on well pads have been documented in many states with oil and gas development...” (Goldman 2013). There are also a number of documented spills from wastewater pits and tanks (Goldman 2013). Wastewater from fracking operations can contain high levels of total dissolved solids (TDS), fracking fluid chemicals, metals, and radioactive materials (U.S. EPA 2014a). “No comprehensive set of national standards exists at this time for the disposal of wastewater discharged from natural gas extraction activities” (U.S. EPA 2014a). There are a few options available to fracking companies, depending on which state the operation is located in. Some wastewater is sent to ordinary municipal or industrial treatment facilities, which then discharge the “treated” water to surface waters. Because these facilities aren’t designed to reduce salinity or remove radioactive and toxic material, the discharged water is often still hazardous (Goldman 2013). There is also some risk in operators intentionally disposing of wastewater improperly. “In 2013 alone, federal prosecutors and state inspectors charged two different hydraulic fracturing wastewater haulers in Ohio with illegal dumping of untreated drilling muds and saline wastewater into surface waters, and similar charges were brought against a Pennsylvania wastewater treatment facility” (Goldman 2013).

There are additional issues related to surface disturbance management that impact surface waters much more routinely and without the negligent or malicious motives of bad actors. The clearing of land and subsequent construction to build well pads, pipelines, and access roads increases erosion and sedimentation, which negatively affects aquatic vegetation and animals (Goldman 2013). These impacts are directly caused by the

development of surface land for oil and gas extraction, which is prerequisite to constructing wells and hydraulically fracturing them. Therefore, there aren't preventative measures for addressing these surface water impacts available to oil and gas companies so much as there are mitigation strategies.

Fracking operations may contaminate groundwater with gases (methane and VOCs) and/or chemicals from fracking fluids. If wells are improperly constructed or maintained, gas may leak out of the well and into an underground source of drinking water (USDW). Cases of gas contamination have been documented in Pennsylvania and Ohio (PA DEP 2009; Ohio DRM 2008). Fractures below the surface, either natural or induced by man, are another potential conduit for USDW contamination as they may allow for a direct exchange of fluids between the fractured shale and a USDW. It is currently unclear whether these subsurface fractures are naturally occurring, caused by drilling, or result from a combination of the two (Goldman 2013). In some cases, groundwater has been contaminated by leaks or spills of fracturing fluid at the surface. Fracking fluids can also migrate underground "...along abandoned wells, around improperly sealed and constructed wells, through induced fractures, or through failed wastewater pit liners" as well as through naturally occurring pathways (Goldman 2013). Where pit liners are not required, fracking fluids and wastewater seep directly into the ground. The risk of groundwater contamination varies in accordance with a number of factors, such as the number of nearby abandoned wells and the quality of construction practices used in drilling, cementing, and casing wells (Goldman 2013). Best practices in engineering and construction of wells can minimize the risk of groundwater contamination. However, the risk of USDW contamination also depends on another

factor. "...Before drilling, it may be difficult to know how big a risk contamination could be, as the extent of the risk appears to depend on the depth of a formation in relation to the depth of drinking water supplies..." (Goldman 2013). North Carolina's geology is such that the distance between USDW and gas-containing shale is significantly smaller than the corresponding water-gas separation in most other shale formations, including the Marcellus Shale. In the Marcellus Shale, residential water wells are 200 ft. deep on average, but occasionally extend over 500 ft. deep; the vertical depth of a typical Marcellus Shale well is 5,000 to 9,000 ft (PSPB 2014). The final report from a 2012 NC DENR study explains:

By contrast (to other states), water supply wells up to 1,000 feet deep have been found in North Carolina's Triassic Basins, and the depth to saline water, if present at all, is unknown. Additionally, in some areas, the shale that might be tapped for natural gas in the Triassic Basins of North Carolina lies at depths of 3,000 feet or less. These factors all point to a much greater potential for contamination of a future potential water supply (Smith 2012).

Using the maximum water well depths of 500 and 1000 ft. respectively, the separation between water and gas supplies ranges from 4,500 to 8,500 ft. in the Marcellus Shale while the separation is a much smaller 2,000 ft. in parts of North Carolina's Triassic Basins. As DENR's report notes, this proximity indicates an increased chance of USDW contamination.

The potential for contamination of water sources is the most salient, polarizing environmental risk related to fracking operations. Research needs exist in all of the above risk areas, but the lack of objective, scientific data concerning the frequency and severity of water contamination cases is particularly problematic. Such factual data is necessary to

provide a meaningful framework through which policy may be discussed and regulation analyzed. Currently, with such limited data, opinionated parties from both sides of the debate justify their positions and support their arguments with theoretical and/or anecdotal evidence. “At the request of Congress, EPA is conducting a study to better understand any potential impacts of hydraulic fracturing for oil and gas on drinking water resources. The scope of the research includes the full lifespan of water in hydraulic fracturing” (U.S. EPA 2014g). This study aims to provide the impartial scientific data requisite for crafting appropriate regulatory policy. However, its scope is nationwide and some states have unique local conditions that require specifically tailored regulation.

The Federal Regulatory Landscape

Federal Regulatory Exemptions

An analysis of U.S. federal policy on hydraulic fracturing primarily consists of identifying the natural gas industry’s exemptions from the various pieces of legislation that would otherwise apply to and regulate activities associated with the hydraulic fracturing process. The relevant acts from which hydraulic fracturing is currently immune include: the Safe Drinking Water Act (SDWA), the Clean Water Act (CWA), the Emergency Planning and Community Right-to-Know Act (EPCRA), the Resource Conservation and Recovery Act (RCRA), the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), and the Clean Air Act (CAA).

The Safe Drinking Water Act’s Underground Injection Control (UIC) program regulates the subsurface emplacement of fluid and is therefore charged with protecting underground sources of drinking water (USDW) (U.S. EPA 2014a). The Energy Policy Act of 2005 curtailed UIC authority by redefining ‘underground injection’ to mean “the

subsurface emplacement of fluids by well injection” and to exclude “the underground injection of natural gas for purposes of storage” and “the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities” (U.S. EPA 2014c). So long as fracking fluid is not diesel-based, underground injection of any substance as a part of fracking operations is allowed without regulation under the SDWA.

The Clean Water Act authorizes the National Pollutant Discharge Elimination System (NPDES) permit program to control discharges. In 1987, amendments to the CWA expanded this program to require permitting for stormwater runoff, but also exempted mining operations and “oil and gas exploration, production, processing, or treatment operations or transmission facilities” from the permitting requirement (Brady 2012). The CWA was amended again in 2005 through the Energy Policy Act to include construction activities as part of the oil and gas production operations exempt from permitting, thus freeing the last remaining part of the hydraulic fracturing process from regulation (Brady 2012). When the EPA issued a rule to reflect this legislative exclusion of construction activities from stormwater discharge permitting, the Natural Resource Defense Council (NRDC) challenged the rule and the Ninth Circuit Court of Appeals sided with NRDC, remanding the rule to the EPA in accordance with its decision (NRDC v. U.S. EPA 2008). Because the EPA has not yet declared a replacement rule, it is uncertain as to whether oil and gas construction facilities are subject to the stormwater permitting requirements of the CWA or whether the statutory exemption remains in effect (Brady 2012; EDC 2011).

The 1986 Emergency Planning and Community Right-to-Know Act was created to help communities plan for emergencies involving spills of hazardous substances. “Section 313 of EPCRA requires EPA and the States to collect data on releases and transfers of listed toxic chemicals that are manufactured, processed, or otherwise used above threshold quantities by certain industries” (Brady 2012). Facilities subject to Section 313 of EPCRA are at the discretion of the Administrator of the EPA, for with him/her lies the authority to add or delete facilities from the Standard Industrial Classification list (Brady 2012). Because oil and gas facilities have not been added to this list, they are exempt from the EPCRA.

The Resource Conservation and Recovery Act is applicable to the wastes generated by hydraulic fracturing operations; either Subtitle C or Subtitle D of the RCRA may regulate the wastes, depending on their classification. Subtitle C authorizes the EPA to conduct a “cradle-to-grave” regulatory program for the generation, transportation, treatment, storage, and disposal of hazardous wastes (U.S. EPA 2014e). Subtitle D regulates non-hazardous solid waste. RCRA instructed the EPA to set criteria for identifying and listing hazardous wastes to be regulated by Subtitle C (RCRA 2014). “In 1988, the EPA completed their required Regulatory Determination of oil field wastes and determined that regulation under Subtitle C was not necessary because existing state and federal regulations were adequate and the economic impact to the petroleum industry would be great” (Brady 2012). The result of this determination was classification of hydraulic fracturing wastes as non-hazardous, subject to regulation only by Subtitle D. Requirements for all stages of the waste production cycle under Subtitle D are less strict and fewer in number than requirements under Subtitle C (Brady 2012).

The Comprehensive Environmental Response, Compensation, and Liability Act gives the EPA power to hold all polluters and potentially responsible parties liable for the cleanup costs of hazardous waste sites (U.S. EPA 2014d). “CERCLA defines a hazardous substance as those substances designated or listed under various statutes, including hazardous wastes listed pursuant to RCRA, as amended by the SWDA, but excludes petroleum, including crude oil, natural gas, natural gas liquids, liquefied natural gas, and mixtures of natural gas and synthetic gas” (Brady 2012). This means that oil or gas spills containing chemicals otherwise considered hazardous are exempt from regulation under CERCLA. This lack of liability effectively absolves industry of financial responsibility for the clean up of spills and provides no incentive for spill prevention efforts.

The Clean Air Act regulates the emission of air pollutants. Section 112 of the CAA mandates the EPA to set emissions standards for hazardous air pollutants (HAPs) from “major sources” and “area sources” (Brady 2012). A “major source” is a stationary source or group of stationary sources in close proximity and under common control that can emit, in the aggregate, at least 10 tons per year of any HAP or at least 25 tons per year of any combination of HAPs (CAA 2014). An “area source” is any stationary source of HAPs that doesn’t have emissions large enough to be considered a “major source” (Brady 2012). Regulations under the CAA are more stringent for major sources than for area sources; major sources are required to obtain a Title V permit while area sources are not (Brady 2012). HAPs emitted from oil and gas exploration and production wells are exempt from the aggregation rule that, for any other activity, would allow for the grouping together of multiple HAP sources to form a major source (EDC 2011). When considered in isolation, almost no hydraulically fractured well emits enough HAPs to be

considered a major source, so virtually all are regulated as area sources (Brady 2012). Because they are treated as area sources, the sites are not required to obtain a Title V permit.

This collection of *ad hoc* exclusions from America's key pieces of environmental legislation, when taken as a whole, culminates in a nearly complete void of federal regulation of hydraulic fracturing. With the small exceptions of diesel-based fracking fluids and potentially stormwater discharges from construction activities, well operators don't need to obtain discharge permits and aren't subject to regulations beyond those of the individual state.

Recent Federal Regulatory Proposals

Federal-level regulation might not be appropriate for all activities of fracking operations, but many stakeholders, including certain states and politicians, believe there should be consistent national regulation across all 50 states for particular aspects of the process (Goss 2013). This mentality has led to a couple of highly controversial, and so far unsuccessful, pieces of proposed legislation: the FRAC Act and the Bureau of Land Management's proposed rule.

The Fracturing Responsibility and Awareness of Chemicals (FRAC) Act, originally introduced to Congress in 2009, was re-introduced in June 2013. The proposed FRAC Act seeks to update hydraulic fracturing regulation in three ways. First, the act would require disclosure of the chemicals used in the fracking fluid, but not the proprietary chemical formula, which would remain a trade secret (Siri 2013). Second, it would "...enact an emergency provision requiring proprietary chemical formulas to be disclosed to a treating physician, the State, or EPA in emergency situations where the

information is needed to provide medical treatment” (Siri 2013). Third, the act would repeal the provision of the Energy Policy Act of 2005 that exempts the oil and gas industry from the SDWA (Siri 2013).

Although numerous environmental groups and some influential policymakers have backed the bill, the natural gas industry, wary of any form of increased regulation, starkly opposes the FRAC Act (Goss 2013). One interest group, Energy In Depth, argues that regulation should continue to be left up to the states, for there is no evidence that state regulation has been inadequate or ineffective (Bell 2013). If the system isn’t broken, the group argues, then don’t fix it. Furthermore, Energy In Depth cites the principle of “subsidiarity,” arguing that policy decisions should be made at the lowest possible level in this case at the state rather than federal level (Andrews 2006; Bell 2013). Another interest group representing the oil and gas industry, American Petroleum Institute (API) issued a study concerned with the economic costs of the FRAC Act. API estimated a cost between \$84 billion and \$374 billion, depending on the realized changes in business practices mandated by the act (IHS 2009). The group’s conclusions were a reduction in U.S. GDP, an increase in unemployment, an enlargement of the federal deficit, and an increase in energy imports (IHS 2009).

Although June of 2013 marks the third time that the FRAC Act has been introduced to Congress, due to extensive pressure from industry, the Act has never made it past committee. The FRAC Act falls short of a comprehensive policy addressing all environmental impacts of hydraulic fracturing, but if the Act were to pass, it would improve the current regulatory system. It focuses on the aspects most critical to public

health by requiring chemical information disclosure and compliance with the SDWA at the national level.

On May 11, 2012, the Bureau of Land Management (BLM) published in the Federal Register a proposed rule entitled Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands. The industry and its interest groups criticized the rule as too burdensome while environmental groups criticized it for not adding enough regulation (Kovski 2013). During the comment period on the BLM's supplemental notice, API filed a letter consisting of arguments against the proposed rule. API concluded that the rule is unwarranted because the risks it seeks to address haven't been legitimized by data or experience and because it would intensify delays in permitting and production, conflict with existing regulations, and result in costs ranging from \$30 million per year to \$2.7 billion per year, depending on how the final regulations would be applied (Milito 2013). Food and Water Watch, 350.org, and the Natural Resources Defense Council were among those organizations submitting letters requesting more comprehensive regulations and a fracking ban on sensitive federal lands (Earthworks 2013).

BLM's proposed rule underwent a number of revisions in response to input received from industry, environmental NGOs, and the general public during the public comment period. The primary components of the revised rule include:

- Provisions for ensuring the protection of groundwater supplies by requiring a validation of well integrity and strong cement barriers between the wellbore and water zones through which the wellbore passes;

- Increased transparency by requiring companies to publicly disclose chemicals used in hydraulic fracturing to the Bureau of Land Management through the website FracFocus, within 30 days of completing fracturing operations;
- Higher standards for interim storage of recovered waste fluids from hydraulic fracturing to mitigate risks to air, water and wildlife;
- Measures to lower the risk of cross-well contamination with chemicals and fluids used in the fracturing operation, by requiring companies to submit more detailed information on the geology, depth, and location of preexisting wells to afford the BLM an opportunity to better evaluate and manage unique site characteristics (BLM 2015).

BLM’s fracking rule, which takes effect June 18, 2015, will apply to “700 million subsurface acres of federal mineral estate and...an additional 56 million acres of Indian mineral estate” (BLM 2015). There are currently over 100,000 oil and gas wells on this land, more than 90% of which are hydraulically fractured (BLM 2015).

Background Information on North Carolina’s Proposed Rule Set

Preexisting Provisions in North Carolina Law

A few rules and regulations in North Carolina were in place before the writing of MEC’s rules. They are narrow in scope and limited in the protections they provide. These provisions include presumptive liability, compensation for damages, site reclamation, bonding, and preempting of local laws. Presumptive liability is discussed later in the third area of potential state regulation, Pre-drilling water testing. The ‘compensation for damages’ rule indicates, “A gas operator must compensate property owner for damages caused to water supply, personal property, livestock, crops, or timber” (Murawski 2014). Operators must also reclaim, or restore, all surface areas within two years after operations are completed (Murawski 2014). Financial assurance is provided through a \$1 million

bond to cover any accrued environmental damages (Murawski 2014). Lastly, local governments are prohibited from passing ordinances that outlaw fracking or effectively prevent shale gas exploration (Murawski 2014).

The Framework and Scope of North Carolina's Rules

In July 2012, the North Carolina General Assembly ratified the “Clean Energy and Economic Security Act,” which reconstituted the Mining Commission as the North Carolina Mining and Energy Commission (MEC) (N.C. DENR 2015a). “The commission is responsible for developing a modern regulatory program for the management of oil and gas exploration and development activities in North Carolina, including the use of horizontal drilling and hydraulic fracturing” (N.C. DENR 2015a). MEC consists of six committees that draft the rules to be voted on by the entire MEC (NCEP 2014a). “Study groups, comprised of MEC members and other interested stakeholders, were also formed to look into specific issues: compulsory pooling, local government regulation, coordinated permitting, trade secrets, and funding levels and sources” (NCEP 2014a).

N.C. S.B. 820 gave the Environmental Management Commission (EMC) responsibility for fracking-related air pollution rules instead of giving this responsibility to MEC (Rivin 2014). MEC therefore felt that they didn't have statutory authority on air emissions (Rao 2015). Dr. Rao of MEC “reappointed a leader for a standing committee and repositioned its focus to study air emissions from fracking to see if they should provide explicit recommendations to the MEC” (Rao 2015). Because MEC doesn't have authority on air emissions and their rule set contains no rules pertaining to air quality, this paper does not examine North Carolina's proposed regulation of fracking-related air pollution (or lack thereof) in great detail. However, it is acknowledged that the

unconventional oil and gas industry causes air pollution of different types in a variety of different ways and that state level regulation may prove to be a viable mitigation strategy.

MEC completed the full set of regulations in May 2014 and the public comment period lasted from July 15 to September 30, 2014 (N.C. DENR 2015a). The rules were adopted by MEC and approved by the Rules Review Commission in December 2014; they are currently pending legislative review (N.C. DENR 2015b). The legislature is expected to ratify the rules in the 2015 long session, after which DENR will be responsible for their enforcement (NCEP 2014a).

Part 2: State Regulation of Fracking in North Carolina and Marcellus Shale States

This section explores possible areas of state fracking regulation through an objective, multifaceted lens that aims to include the positions of all stakeholders. After a brief introduction of the regulation and explanation of its underlying rationale, the experiences of Marcellus shale states will be examined. The Marcellus shale is the most expansive shale formation in the U.S. Though the underground shale formation overlaps additional states (and even parts of Canada) to a small extent, only four states will be included in the analysis of the Marcellus shale experience: Pennsylvania, Ohio, New York, and West Virginia. The vast majority of the shale formation is contained within these four states. New York currently has a moratorium on fracking, but the state still has regulations for various parts of the fracking process in place and is in the process of drafting more as it considers lifting the moratorium. It should be noted, however, that as a result of New York's moratorium, many of New York's rules haven't been updated for some time. This is similar to North Carolina's current situation, as MEC's rules have not

yet been implemented at the time of this paper's writing. The remaining three Marcellus Shale states (Pennsylvania, Ohio, and West Virginia) are currently all major producers of natural gas. Next, North Carolina's proposed regulation for the relevant area will be examined. The industry's position is portrayed through American Petroleum Institute (API) best practices for each area of regulation. Finally, the position of environmental groups, particularly North Carolina Environmental Partnership (NCEP), will be considered. NCEP is composed of the following groups: Natural Resources Defense Council, Southern Environmental Law Center, North Carolina Conservation Network, Waterkeeper Alliance, Haw River Assembly, Neuse Riverkeeper Foundation, and Waterkeepers Carolina. When discussing certain regulations, some of the above information may be omitted where it is either unavailable or inapplicable. Emphasis is placed on the more salient and/or controversial areas of the regulatory framework.

Site Selection and Preparation

Well Spacing Rules

Well spacing refers to the required distance between wells; these rules are based on geographic drilling units, usually 640 acres in size (Richardson 2013). In addition to regulating spacing between wells, states may also establish a minimum distance from drilling unit boundaries (Richardson 2013). MEC has proposed a 500 ft. minimum distance from boundaries of the drilling unit (15A NCAC 05H .1105). There is a general consensus that wells should not be located too close to each other, for both environmental and economic reasons. Due to the unanimity of stakeholder opinion over this regulation, it will not be further explored.

Setback Requirements from Buildings

Setback requirements regulate the minimum allowable distance between wells and other pertinent entities, usually buildings and water sources. One strong reason for establishing setbacks from buildings is the potential exposure to toxic air emissions emanating from fracking sites. Setback requirements can either be applied to all occupied buildings or only to specific buildings such as schools and churches (Richardson 2013). Normally, building setbacks are measured from the wellbore.

Pennsylvania uses a setback of 500 ft. from buildings, which was recently increased from 200 ft (Richardson 2013). West Virginia requires a slightly further setback distance of 625 ft. from buildings (Richardson 2013). Ohio requires a setback of only 100-200 ft., but also has setbacks from mechanical separators, tank batteries, railroad tracks, and public roadways (Richardson 2013). API best practices maintain, “When feasible, the well site and access road should be located as far as practical from occupied structures and places of assembly” (API 2011). Unfortunately however, API doesn’t provide a specific distance. The proposed setback distance in North Carolina’s rules is 650 ft. from occupied buildings (15A NCAC 05H .1503). A nonprofit environmental organization, Clean Water for North Carolina (CWNC), weighs in by claiming that 650 ft. is not far enough (CWNC 2014). CWNC also fails to provide a figure for what they believe to be a sufficient distance. “Occupied dwelling” is broadly defined in MEC’s proposed rule set, and so the 650 ft. setback is a stronger setback regulation than those of the Marcellus Shale states.

Setback Requirements from Water Sources

Water contamination is the main concern here and regulation amongst Marcellus Shale states displays much heterogeneity. West Virginia requires a setback distance of 250 ft. from water wells (recently increased from 200 ft.), and mandates 100 ft. between well pads and streams (with a 300 ft. setback from naturally reproducing trout streams) and 1000 ft. between well pads and public water supplies (Richardson 2013). Pennsylvania's setback requirement has been increased from 200 to 1000 ft. for public water supplies and from 100 to 300 ft. for streams and wetlands (Richardson 2013). Ohio only requires a setback from water of 50 ft., although Ohio, Pennsylvania, and New York have additional setback restrictions from other water sources such as lakes, streams, and private water wells (Richardson 2013).

API best practices suggest, "where feasible, locate sites away from sensitive areas, such as surface waters and freshwater wells." Again, no quantitative recommendation is provided (Richardson 2013). The North Carolina MEC has proposed a setback of 200 ft. from all surface waters and 650 ft. from public and private water wells (15A NCAC 05H .1503). Clean Water for North Carolina advocates for a minimum setback of 1000 ft. from private water wells and 1500 ft. from public water supply wells (CWNC 2014). More scientific studies are needed to determine whether or not the MEC's proposed setback distance is adequate to protect water quality.

Pre-Drilling Water Testing

Water wells in the vicinity of fracking operations can be tested before drilling begins to establish baseline water quality for the area. After drilling activities commence, if groundwater is found to be contaminated, pre-drilling water tests are important for

determining whether fracking operations are related to the contamination (Richardson 2013). There are two policy alternatives for utilizing pre-drilling water testing. The first is a command-and-control type regulation, which requires water wells within a certain distance of the drill site to be tested. In Ohio, water wells within 0.28 miles of a natural gas well must be tested (Richardson 2013). In New York and West Virginia, baseline water testing is only required within a distance of 0.19 miles of natural gas wells (Richardson 2013). The second alternative is a policy of presumptive liability. Pennsylvania provides an example of this burden-shifting rule, which prohibits an operator from claiming (in legal action) that contamination was preexisting if the operator didn't test water before drilling. In Pennsylvania, "although plaintiffs retain the burden of proof that some contamination exists, such contamination within 2,500 feet of wells and within one year of drilling is presumed to be attributable to the operator defendant unless rebutted with pre-drilling testing evidence" (Richardson 2013). The spatial and time scales for presumptive liability in Pennsylvania have been increased from 1,000 feet and six months respectively (Richardson 2013). The efficiency argument for crafting policy in accordance with presumptive liability (rather than command-and-control) is that the operators who decide whether pre-drilling testing is necessary or cost-effective for a particular well make this decision with a strong incentive to get it right (Richardson 2013).

API best practice is to take pre-drilling samples from any source of water located near the well before drilling or hydraulic fracturing (Richardson 2013). The testing distance is determined from anticipated fracture length of the gas well plus a safety factor; therefore API's recommendation is variable, unlike the fixed standard of a

regulation (Richardson 2013). North Carolina would use a combination of these two policy alternatives. A provision for presumptive liability already exists in North Carolina law (Murawski 2014). In 2013, the presumptive liability distance for water contamination from oil and gas operations was reduced from 5,000 feet to a half mile (N.C. S.B. 786 2013). MEC's rules require pre-drilling testing of all water supplies within one-half mile of a gas wellhead between 30 days and 12 months before drilling begins (15A NCAC 05H .1803). The rules also provide instructions for five subsequent tests of these same water supplies, the first to be conducted 6 months after production has commenced, the fourth at two years after production has commenced, and the fifth at 30 days after completion of production (15A NCAC 05H .1803). Water is to be tested for levels of arsenic, barium, radium, benzene, and diesel among many other potential contaminants and water quality indicators (15A NCAC 05H .1803). The rule proposal stipulates that testing is to be paid for by the drilling permit holder and conducted by an independent lab (15A NCAC 05H .1802). The North Carolina Environmental Partnership advocates that the presumptive liability distance should be restored back to 5,000 feet (as it was before 2013) or at least extended to 3,000 feet as a 2011 Duke University study recommended (NCEP 2014b). NCEP also wants the requirement for baseline water testing extended from two years after drilling to four or six years after drilling (NCEP 2014b).

Drilling the Well

Maintaining long-term integrity and safety of wells is critical for groundwater protection and can be accomplished through adequate casing and cementing of the wellbore. Environmental groups generally find the various (N.C.) regulations discussed

in this section acceptable, in part because the details are technical and expertise in well construction standards lies with the industry's engineers.

Surface Casing and Cementing Depth

Well casing is made of steel pipe that separates the wellbore from surrounding rock.

Casing can be divided into four general types, in decreasing order of diameter.

Conductor casing is set at the surface in many cases, including in conditions where surface soils may cave during drilling. Surface casing is then set, followed by intermediate and production casing, each set within the preceding, larger-diameter casing.

This creates a series of concentric cylinders—the casing string. Cement is circulated within the gap (annulus) between each layer of casing (Richardson 2013).

Casing/cementing depth rules generally require surface casing to be run and cemented down to a certain distance below the water table.

This required distance is 75 feet in New York, 50 feet in Pennsylvania and Ohio, and 30 feet in West Virginia (Richardson 2013). API best practice says, “at a minimum, it is recommended that surface casing be set at least 100 ft below the deepest USDW [underground source of drinking water] encountered while drilling the well” (Hydraulic). Therefore, none of the Marcellus Shale states’ regulations are sufficient to meet the API best practice. The proposed rule in North Carolina reads: “Surface casing shall be set into competent bedrock to a depth of at least 100 feet below the base of the deepest groundwaters but above any hydrocarbon strata containing fluids or gases that could negatively impact the quality of the cement or proper functioning of the well” (15A NCAC 05H .1510). In conforming to the API best practice, North Carolina will soon

provide a model for the Marcellus Shale states in sufficient well casing and cementing depth regulation.

Cement Type

“Cementing practices may be regulated in terms of compressive strength, type of cement, or circulation around casing. Class A Portland cement is the most commonly required type of cement for setting casing in place. Cement types vary by well and by operator and depend on local geological and other conditions” (Richardson 2013).

Industry best practice includes consulting the appropriate API standard ‘Specification 10A’ in selecting cement type in addition to laboratory testing of cements, additives, and mixing fluids to ensure that they are compatible with the well design (API 2009b). New York’s proposed legislation explicitly incorporates the API standard, mandating that cement must conform to API Specification 10A and contain a gas-block additive (Richardson 2013). The North Carolina rules similarly incorporate the API standard where they propose “All cement pumped into the wellbore shall consist of Portland cement that is manufactured and tested pursuant to API Specification 10A ‘Specification for Cements and Materials for Well Cementing’ or the American Society for Testing and Materials (ASTM) Standard Specification ‘C150/C150M Standard Specification for Portland Cement’” (15A NCAC 05H .1509).

Cement Circulation

In the well drilling process, cement is circulated between adjacent layers of casing. The regulations for each type of casing (surface, intermediate, and production) are discussed below. These regulate how far cement must be placed up a certain layer of casing (starting from the bottom of the casing layer).

Surface Casing Cement Circulation

All four Marcellus Shale States require cementing of surface casing to extend to the surface. The proposed rule in North Carolina similarly states “surface casing shall be cemented from bottom to top” (15A NCAC 05H .1510). The proposed rule for conductor casing, which is sometimes placed on the outside of surface casing, is the same. API best practice states “that the surface casing be cemented from the bottom to the top,” but if that cannot be attained, API recommends cementing across all USDW (API 2009b). This API standard combines recommendations for casing/cementing depth requirements and cement circulation requirements (Richardson 2013). Because the Marcellus Shale states, N.C., and API are all in agreement, this area of regulation is settled.

Intermediate Casing Cement Circulation

Agreement on regulation of cement circulation in intermediate casing is much less unanimous. In New York and Pennsylvania, a command-and-control rule requires that cement of intermediate casing must be circulated to the surface (Richardson 2013). Ohio rules specify that intermediate casing must be cemented to a distance of 500 ft. above the bottom of the casing string or uppermost hydrocarbon zone. West Virginia uses its permitting processes to regulate intermediate casing cementing depth. API recommends that enough cement be circulated around intermediate casing to isolate all USDW and hydrocarbon zones from the wellbore. API best practice is “if the intermediate casing is not cemented to the surface, at a minimum the cement should extend above any exposed USDW [underground sources of drinking water] or any hydrocarbon bearing zone” (API 2009b). MEC proposes “The casing string shall be cemented from the bottom to a minimum of 100 feet above the top of the shallowest groundwaters” (15A NCAC 05H

.1510). The rule in NC is less stringent than the intermediate casing cement circulation regulations in New York and Pennsylvania, but more stringent than comparable regulations in other states. The proposed N.C. regulation is unique in that it uses freshwater zones instead of the casing string or hydrocarbon zones as the reference point.

Production Casing Cement Circulation

Cement circulation rules for this layer of casing are very heterogeneous. New York is one of only two states that require production casing to be cemented to the surface (Richardson 2013). “Pennsylvania mandates cement circulation 500 feet from the true vertical depth” (Richardson 2013). Ohio requires cementing to 1000 ft. above the shoe/hydrocarbon zone; West Virginia addresses this regulation in its permitting process (Richardson 2013). API best practice recommends cementing production casing to “at least 500 ft above the highest formation where hydraulic fracturing will be performed” (API 2009b). MEC’s proposed regulation for N.C. reads “Production casing shall be installed and cemented from the bottom to 600 feet above the uppermost perforation, a potential corrosive zone, an oil or gas bearing zone, or a potential water supply” (15A NCAC 05H .1510). Production lining will be allowed as a substitute for production casing in North Carolina if certain conditions are met. The discrepancy in reference point(s) used in each state makes a cross-state comparison difficult if even possible. However, North Carolina’s proposed rule clearly surpasses API best practice in terms of stringency.

Some states have recently proposed changes to casing and cementing standards, the most common of which involves pressure testing. Essentially, this requires the well to be pressure tested prior to fracking to prove that the cement and casing can withstand the

maximum pressures that fracking activities will cause (Richardson 2013). North Carolina's MEC showed foresight by including such a provision in the Well Construction Requirements section of their rules. The rules state "Casing shall be designed to have a minimum internal yield pressure rating that is 20 percent greater than the maximum anticipated pressure to which the casing may be subjected during drilling, completion, or production operations" (15A NCAC 05H .1508). The rules go on to specify that pressure testing of all cemented casing strings longer than 200 ft. must be completed using a comprehensive testing method, which is explained later in this section of the rules (15A NCAC 05H .1508).

Hydraulic Fracturing

Water Withdrawal

Fracking is a water-intensive process that consumes several million gallons of water per well (GPC 2015c). Even if fracking fluid is recycled, new fracking jobs require additional water. When surface water is used, large water withdrawals may affect downstream users and ecosystems. "API best practice stipulates that 'consultation with appropriate water management agencies' is a 'must' and that 'whenever practicable operators should consider using non-potable water for drilling and hydraulic fracturing'" (Richardson 2013).

The regulatory experiences of Marcellus Shale states are diverse. In Ohio, withdrawals over 100,000 gallons per day require registration and reporting and withdrawals over 2,000,000 gallons per day require a permit (Richardson 2013). In New York, a permit is required for water withdrawals of over 100,000 gallons per day (Richardson 2013). At the other end of the spectrum,

Pennsylvania requires a water management plan covering the full lifecycle of the water used in shale gas production, including the location and amount of the withdrawal and an analysis of the impact of the withdrawal on the body of water from which it came.

Pennsylvania and the Susquehanna RBC require permits for any water withdrawals for fracking and operate ecosystem models that provide the basis for rejecting applications for water withdrawals that would put stress on ecosystems (Richardson 2013).

Similar to Pennsylvania, N.C. Mining and Energy Commission's proposal requires a water management plan for all water withdrawals for the purposes of oil and gas exploration, development, or processing. However, the proposed NC rule fails to explicitly address effects of surface water withdrawal on ecosystems. For surface water sources, NC operators would only need to provide "the results of a survey to determine the presence of any state or federally threatened or endangered species or any invasive species that may be affected by the proposed withdrawal..." (15A NCAC 05H .1804). If a protected species is present, the permit holder must describe how potential adverse impacts will be avoided. This provision wouldn't come close to matching the scope and the technical precision of Pennsylvania's permitting process, which is based on ecosystem models. As they currently stand, NC's rules include the water management plan as part of the drilling permit, but N.C. Environmental Partnership wants a separate permitting process for water withdrawals. Although North Carolina requires a management plan for any amount of water withdrawal, there is room for improvement in this area of regulation and Pennsylvania provides a good model.

Fracking Fluid Disclosure

One of the most controversial and dynamic aspects of hydraulic fracturing regulation is the disclosure of chemical additives in fracking fluid. Currently, there are

two options for chemical disclosure that states commonly use. The first, FracFocus.org, is the national hydraulic fracturing chemical disclosure registry where companies voluntarily register well sites that have been fractured since the date they joined, including information pertaining to some of the chemicals used in the fracking fluid. Most states requiring chemical disclosure rely on FracFocus.org (Richardson 2013). As of March 2015, less than 100,000 total well sites have been registered and “about 20% of all hydraulic fracturing chemicals are not disclosed on FracFocus forms” (GPC 2015a; Konschnik 2013).

The second avenue for disclosure consists of Material Safety Data Sheets (MSDS) and Tier II Chemical Inventory Reports, two mediums for collecting data about the chemical formulation of potentially hazardous products, some of which are used in hydraulic fracturing fluid. However, these forms are often incomplete and/or inaccurate. MSDS forms are only required for hazardous chemicals stored in quantities of at least 10,000 pounds. Guidelines for the format and content of MSDS, instituted by the U.S. Occupational Safety and Health Administration (OSHA), are vague and limited in scope, leaving the decision of what is actually reported largely up to the manufacturers of the products (Colborn). Manufacturers describe ingredients of products by their functional purpose or simply identify them based on their general chemical class, effectively disguising pertinent and crucial information. Some Tier II forms contain no actual product name and many omit the fraction of the total product each ingredient accounts for (Colborn). Furthermore, MSDS often fail to provide Chemical Abstract Service (CAS) numbers—numbers that the American Chemical Society established to identify unique chemical substances (Colborn). “Some stakeholders argue that limiting disclosure for

fracturing fluids to MSDS data is insufficient because of the lack of ingredient data, the exemptions provided, and the number of chemicals used that are not listed as hazardous even though they may endanger human and environmental health” (Richardson 2013).

All Marcellus Shale states require some form of fracking fluid disclosure (or have proposed a disclosure requirement in the case of NY). Pennsylvania also requires the disclosure of the percentage by volume of each additive in the stimulation fluid. Crucially important, “all states with chemical disclosure requirements provide trade secret exemptions for chemicals considered ‘confidential business information’” (Richardson 2013). API advises operators to be ready to disclose chemical additives and their ingredients; API best practice is “...to use additives that pose minimal risk of possible adverse human health effects to the extent possible in delivering needed fracture effectiveness” (API 2010).

Because reporting requirements for chemical ingredients used in the products that are found in fracking fluid are laissez-faire in nature, the decision of what to report and how to report it is largely left up to industry. Due to the hazardous properties of many of the chemicals used, it is in the individual company’s best interest to not disclose certain chemicals and to disclose in a way that makes their chemical use seem as benign as possible. The result is information asymmetry, where the fracking companies know by far the most, the government knows significantly less, and the general public knows little to nothing.

A number of study groups, advocacy organizations, and the North Carolina Attorney General argue that trade secrets should be eliminated; without this exemption, everything would be mandatorily disclosed (Murawski 2014). Similarly, the North Carolina

Environmental Partnership makes the following recommendations: (1) Operators should be required to fully disclose and make publicly available, constituent chemicals and their corresponding CAS numbers for all chemicals used in drilling and fracking fluids; (2) Even when the fracking fluid formula is secret, all component chemicals should be public information; (3) The legislature should remove the provision that criminalizes the unauthorized disclosure of fracking fluid composition (NCEP 2014c).

Wastewater Storage and Disposal

Depending on the geological characteristics of the shale play and well, between 10 and 30% of the fracturing fluid will eventually flow back up and out of the wellbore (PSPB 2014). This includes flowback and produced (formation) water, which are collectively referred to as “wastewater.” ‘Flowback’ is the portion of the fracturing fluid that flows back up to the surface, which now contains dissolved metal ions and total dissolved solids (TDS) in addition to the chemical additives of the original fracking fluid. Produced water originates from the formation itself and contains high levels of TDS and minerals that have leached out from the shale including barium, calcium, iron and magnesium. “It also contains dissolved hydrocarbons such as methane, ethane and propane along with naturally occurring radioactive materials (NORM) such as radium isotopes” (Schramm 2011). The composition and toxicity of wastewater varies widely, but all wastewater requires storage and disposal. Some wastewater may be recycled for use in future fracking operations. “Failure to properly store, recycle, or dispose of wastewater increases the risk of spills or leaks that can lead to surface or groundwater contamination” (Richardson 2013).

Wastewater Storage

Fluid Storage Options

Operators have a number of options available to them for temporarily storing the variety of fluids used in and produced by the fracking process. There are three main types of fluids used or produced by the process that must be stored. Fracturing fluids must be stored before they are injected into the ground during the hydraulic fracturing part of the process. After fracking takes place, the remaining two fluids, flowback and then produced water, flow to the surface. Most flowback occurs in the first seven to ten days after fracking takes place (Schramm 2011). Produced water flows to the surface throughout the whole lifespan of the well (Schramm 2011). “Fluids are most commonly stored in open pits or closed tanks. Some state regulations mention storage of wastewater in ponds, sumps, containers, impoundments, and ditches, but all of these can be considered subtypes of pits or tanks” (Richardson 2013).

New York requires sealed tanks for some fluids. New York’s proposed regulation would require flowback water to be stored in watertight tanks, whereas other wastes could be stored in pits. In West Virginia and Pennsylvania, open pits are allowed and regulated for all fluids. “In 2012, Pennsylvania’s Department of Environmental Protection recommended eliminating the storage of produced fluids in pits: ‘The long-term storage of production fluids in a pit presents an unacceptable risk to the environment through leaks or overtopping of the pit’” (NCEP 2014d). Ohio requires a permit for all pits and tanks. Industry best practice, per API, details that “completion brines and other potential pollutants should be kept in lined pits, steel pits, or storage tanks” (API 2009a). The proposed rules for North Carolina allow all types of wastewater to be stored in open-

air pits, open tanks or closed tanks. Pits and open tanks must be inspected after a half-inch of rain falls within a 24-hour period (Murawski 2014).

NCEP opposes the use of open pits, claiming that they create a significant and avoidable hazard as floods and leaks occur and liners wear out and can be pierced by the activities of wild animals. “Some constituents of fracking wastewater, such as benzene and other volatile (light) hydrocarbons, enter the air when the liquid is exposed to the atmosphere” (NCEP 2014d). NCEP would like all wastewater to be managed in a closed loop system, which would require wastewater to be stored in watertight tanks surrounded by another structure for secondary containment. If open pits are to be allowed, NCEP argues that the setback distance from open pits to streams or other surface waters should be increased from 200 to 2000 feet (NCEP 2014d).

Freeboard

Freeboard is the distance between the top of an open pit and its maximum fluid level. It is important for preventing the overflow of fluids contained in the pit, especially during and after heavy rainfall events (Richardson 2013). New York, Pennsylvania, and West Virginia have a 2 feet freeboard requirement; Ohio has no freeboard requirement (Richardson 2013). The API best practice doesn't provide a specific freeboard length; rather, it simply states that pits should be constructed with enough freeboard “to prevent overflow under maximum anticipated operating requirements and precipitation” (API 2009a). The N.C. Mining and Energy commission's rule proposal includes a freeboard requirement of 2 feet, the same requirement that New York, Pennsylvania, and West Virginia use (15A NCAC 05H .1405). The N.C. Environmental Partnership is advocating for the freeboard requirement to be increased from 2 feet to 4 feet.

Pit Liners

Open pits are often lined with pit liners to prevent fluids from seeping into the ground where they might contaminate groundwater. Ohio does not require open pits to be lined. However, pit liners are required in Pennsylvania, West Virginia, and New York. New York specifies a minimum thickness of 30 mm for the liner. API best practice is that “depending upon the fluids being placed in the impoundment, the duration of the storage and the soil conditions, an impound lining may be necessary to prevent infiltration of fluids into the subsurface” (API 2010). API’s choice of diction (“depending... may be necessary”) implies that not all pits necessitate liners and the criteria for determining those pits that do is based on the characteristics of both the soil and the fluids being stored. While soil types vary enormously, no soil is completely impermeable. Therefore, without a liner, fluids stored in open pits would eventually penetrate the subsurface soil. Furthermore, fluids stored in these pits would almost certainly have some of the hazardous properties discussed above. Wastewater—flowback and produced water—are the fluids most likely to be stored in open pits. Pit liners are a simple and cost-effective way to protect soil quality and, by extension, water quality from the various contaminants found in the variety of fluids used by and produced by the fracking process. North Carolina’s rules specify, “If an exposed pit is used, the pit must be double-layered with synthetic liners and equipped with leakage monitors between the liners” (Murawski 2014). If the liner is made of Polyvinyl chloride (PVC), it must be at least 30 mm thick and if it’s made of high-density polyethylene (HDPE), it must be at least 40 mm thick (15A NCAC 05H .1405). While NCEP opposes regulation allowing open pits as a storage

option, the pit liner requirements proposed for North Carolina by MEC seem comprehensive enough to satisfy most environmentally concerned parties.

Wastewater Disposal

Underground Injection

In some states, certain wastes may be injected deep underground into so-called underground injection wells. Underground injection is the most common fluid disposal method allowed by state regulations. In the Marcellus Shale states (Pennsylvania, New York, West Virginia and Ohio), underground injection is allowed, but regulated (Richardson 2013). Ohio recently and temporarily closed several injection wells in an area where seismic activity has occurred, awaiting the results of further research (Richardson 2013). There has been some concern over whether fracking poses a danger through induced seismic activity. However, where seismic activity has occurred, its frequency and intensity have been much greater near wells where wastes were injected underground (Class II injection wells) rather than near wells where fracking was occurring. Hydraulic fracturing itself has been linked to mild seismic activity—less than 2 moment magnitude—which is typically undetectable at the surface (NRC 2013). The disposal of wastewater in Class II injection wells, however, has been linked to larger earthquakes (NRC 2013). “At least half of the 4.5 M or larger earthquakes to strike the interior of the United States in the past decade have occurred in regions of potential injection-induced seismicity” (Goldman 2013). North Carolina law prohibits the underground injection of wastewater produced from oil or gas operations within the state and, although the General Assembly recently considered lifting this ban, it’s now evident that MEC’s rules will maintain the existing ban (15A NCAC 05H .1904). While API

says, “disposal of flow back fluids through injection, where an injection zone is available, is widely recognized as being environmentally sound, is well regulated, and has been proven effective,” NCEP maintains that wastewater cannot be safely injected underground in North Carolina (API 2010; NCEP 2014a).

Other Disposal Options

Other than underground injection, operators have a number of other options potentially available for wastewater disposal, depending on the regulations of the state they’re located in. These potential options include: treatment facility, evaporation pond/disposal pit, land application, discharge to surface water, and recycling.

...Although a treatment facility is a ‘disposal option’ from the point of view of a gas operator (and therefore from the point of view of regulations governing those operators), the eventual fate of waste products depends on the practices of and regulations aimed at those treatment facilities. After treatment, fluids may be discharged into surface water, buried, applied to land or roads, or otherwise disposed of (Richardson 2013).

Due to its ability to reduce both water withdrawals and waste generation, recycling wastewater is recommended where possible. That said, depending on the composition of wastewater, recycling is not always possible and in any case, wastes will eventually require disposal. API best practice suggests that operators consider recycling options for flowback and API approves of the following waste disposal options: land- and road-spreading, on-site burial, on-site disposal pits, annular injection, underground injection, permitted discharge of fluid, incineration, and off-site commercial facilities (Richardson 2013).

Some Marcellus Shale states have recently updated their wastewater disposal options and requirements. “Ohio previously allowed roadspreading of brine but added a

provision to its code clarifying that ‘[o]nly brine that is produced from a well shall be allowed to be spread on a road’ and that roadspreading is prohibited for ‘fluids from the drilling of a well, flowback from the stimulation of a well, and other fluids used to treat a well’” (Richardson 2013; Ohio DNR 2008). As used above, “brine” is synonymous with wastewater. Pennsylvania requested that well operators stop sending wastewater to 15 wastewater treatment facilities within the state (PA DEP 2011).

Solid waste materials—drill fluids, drill muds, and drill cuttings—are also produced during the drilling process. These solid wastes are considered to pose a lesser environmental risk than wastewater, partially because they are produced in much smaller quantities (Richardson 2013). Unlike the rules pertaining to wastewater, in some states, these solids may be buried on-site or placed back into the wellbore (Richardson 2013). Pennsylvania allows all drill cuttings to be disposed of through land application.

MEC’s rule proposal stipulates, “Permit holder must submit a management plan for storing and handling wastewater and solid wastes from the entire exploration process including final disposal” (Murawski 2014). Under this rule, a permit can be issued for a treatment facility to ‘treat’ wastewater and then discharge the treated waste into rivers and lakes. N.C. Environmental Partnership maintains that no safe option exists for fracking wastewater disposal within the state of North Carolina. Their “fact sheet” explains:

North Carolina lacks water quality standards or effluent limit guidelines for many fracking contaminants. That means a permit can be issued for a facility to ‘treat’ and discharge fracking wastes into rivers and lakes without removing many of the contaminants of concern. Essentially, North Carolina lacks the necessary regulatory framework to ensure safe surface disposal (NCEP 2014f).

Further, North Carolina's wastewater treatment plants weren't designed to remove fracking contaminants (NCEP 2014f). N.C. Environmental Partnership's position eliminates any means of wastewater disposal in North Carolina on the grounds that all potential options present unreasonable risk. However, transporting the waste outside state borders would only pass off the problem to a neighboring state rather than providing an actual solution. Such a policy would also accelerate road deterioration and increase the likelihood of spills and truck accidents, as trucking is the preferred mode of transportation for wastewater (NCEP 2014f).

Wastewater Transportation Tracking

“Wastewater that is not reused, recycled, or disposed of on-site must be transported elsewhere for disposal, sometimes in pipelines but usually by truck” (Richardson 2013). West Virginia and Pennsylvania both require recordkeeping by transport firms, Pennsylvania for 5 years (Richardson 2013). In addition to recordkeeping, New York and Ohio also require a permit and/or approval for wastewater transport. Furthermore, Ohio requires yearly reports of waste receipts. “Generally, recordkeeping requirements include the names of the operator and transporter, the date the wastewater was picked up, the location at which it was picked up, the location of the disposal facility or destination of the shipment, the type of fluid being transported, the volume, and how it is being disposed of” (Richardson 2013). Responsibility for tracking and reporting information may fall on either well operators or wastewater transport firms. The API best practice recommends that wastewater be transported “in enclosed tanks aboard [US Department of Transportation] compliant tanker trucks or a dedicated pipeline system” (API 2011). While the best practice specifies the manner and method of

transport, API never explicitly recommends any type of recordkeeping practice. MEC's rules propose that when fracking wastes are transported offsite, it is the permittee's responsibility to maintain copies of invoices, bills, tickets, and other records for a minimum of five years (15A NCAC 05H .1904). These records must include all of the information typical of recordkeeping requirements and document the entire lifecycle of transported wastes (15A NCAC 05H .1904). This rule goes beyond API's best practice and would place North Carolina at the forefront of comprehensive wastewater tracking regulation. Therefore, environmental groups such as NCEP take no issue with the proposed rule.

Excess Gases

Before and during production, some gases—excess gases—cannot be stored or used commercially (Richardson 2013). Two methods are employed to dispose of these gases. Venting simply releases the gas directly into the atmosphere. Flaring is the controlled burning of this gas. Venting and flaring both have environmental consequences. “They may result in emissions of volatile organic compounds (VOCs) or other pollutants regulated due to their effects on human health. Both venting and flaring also result in GHG emissions—venting of natural gas releases methane, a potent GHG, whereas flaring emits carbon dioxide” (Richardson 2013). For these reasons, venting and flaring are often regulated by states (Richardson 2013).

Venting

As noted above, venting releases (mostly) methane gas from the wellbore into the air. Because natural gas is primarily methane, the gas vented in fracking operations is gaseous methane produced during the initial drilling and fracking process. Venting

regulation varies across the Marcellus Shale states. The practice is restricted, but not banned in New York and Ohio. In a few (non-Marcellus Shale) states, there is an outright ban on venting. Pennsylvania and West Virginia have a discretionary or aspirational standard. “These require operators to minimize gas waste or avoid harm to public health but probably do not create any enforceable requirement” (Richardson 2013). API best practice recommends flaring rather than venting.

Flaring

In flaring, excess gas is burned off in gas flares, also known as flare stacks (Richardson 2013). Through combustion, methane gas is converted into carbon dioxide. While both carbon dioxide and methane are greenhouse gases, methane has about 30 times the potency of carbon dioxide as a heat-trapping gas (Princeton 2014). The flaring regulations of the Marcellus Shale states match up with their respective venting regulations. Like venting, flaring is also restricted in New York and Ohio. Pennsylvania and West Virginia have discretionary or aspirational standards similar to those that they have for venting. These idealistic standards mandate that operators minimize excess gas or avoid harming public health but, like the venting standards, carry no enforceable requirement. “API suggests that all gas resources of value that cannot be captured and sold should be flared and recommends that flares be restricted to a safe location and oriented downwind considering the prevailing wind direction at the site” (Richardson 2013).

EPA’s Green Completion Rule

Beginning January 1, 2015, a new EPA air pollution rule for the oil and natural gas industry will take effect (NCEP 2014e). This rule requires fracking operators to use

green completions, otherwise known as reduced emission completions (REC), to capture excess gases (U.S. EPA 2012b). Green completions will replace venting and flaring, thereby reducing air pollution and waste (U.S. EPA 2012b). Because North Carolina has not written rules for air pollution at fracking sites, the state will, by default, rely on the EPA green completion rule and other EPA air quality regulations (Rivin 2014).

N.C. Environmental Partnership and other environmental groups argue that, because this EPA rule focuses solely on excess gasses released from the wellhead, its scope is too narrow to address the whole range of air pollution sources found at fracking sites; these environmental interests recommend a comprehensive regulatory framework at the state level to monitor and control toxic air pollutants (NCEP 2014e; Rivin 2014). The EPA's rule also exempts exploratory and wildcat wells from this REC requirement, which is concerning because many of the wells drilled in North Carolina are likely to be exploratory or wildcat (NCEP 2014e). N.C. Environmental Partnership recommends that the Mining and Energy Commission should require all gas wells (including exploratory and wildcat wells) drilled in North Carolina to have green completions (NCEP 2014e).

Production (Severance) Taxes

Severance taxes are taxes levied on gas production; specifically, those based on the volume of gas extracted (Richardson 2013). Though not technically a regulation, severance taxes represent a key linkage between the natural gas industry and the state governments that regulate the industry. As previously noted, fracking can provide substantial economic benefits and part of these benefits is an increase in state revenue through associated fees and taxes. "States generally use one of two methods to calculate

the tax—either a percentage of the market value of the gas extracted (18 states) or a fixed dollar amount per quantity extracted (5 states)” (Richardson 2013).

Amongst Marcellus Shale states, there is significant heterogeneity. West Virginia’s severance tax is based on a percentage of the extracted gas value, while Ohio’s is calculated as a fixed amount per unit of gas extracted. Neither Pennsylvania nor New York has a severance tax per se. Instead of a severance tax, Pennsylvania uses an “impact fee,” a standard fee charged on each well, the amount of which is unaffected by production level of the well (58 Pa. C.S. §3201-3274). The impact fee only applies to those operating within a county that has chosen to adopt the fee (58 Pa. C.S. §§3201-3274). Although New York’s fracking moratorium is still in place and the state doesn’t currently levy severance taxes on conventional gas operations, if and when the moratorium is lifted, New York could institute such a tax on unconventional shale gas operations (Richardson 2013).

North Carolina currently taxes the production of gas at 0.05 cents (\$0.0005) per thousand cubic feet (Richardson 2013). Depending on the prevailing market price of natural gas, this tax rate expressed in percentage form is between 0.01% and 0.02%. The upper- and lower-bound estimates of market price—\$5.40/Mcf and \$2.46/Mcf—are based on the EIA’s price forecast for 2030 and the Henry Hub price in 2012 respectively (Richardson 2013; U.S. EIA 2013). Of the states that use a severance tax, North Carolina’s (existing tax rate) is by far the lowest; Illinois’s severance tax of 0.1% is the second lowest (Richardson 2013). Depending on the prevailing market price of natural gas, Illinois’s tax rate is five to ten times the amount of North Carolina’s. At the upper end of the spectrum, Montana has the highest severance tax rate of 9%—a staggering 450

to 900 times North Carolina's current tax rate. It should be noted, however, that Montana's tax rate of 9% is a long-term rate that applies only after the first 18 months of a well's production; Montana initially levies a much smaller rate of 0.5% during a well's first 18 months (Richardson 2013).

In North Carolina, MEC's rules address the topic of severance taxes and indicate that there will most likely be a revision in the tax rate. A study group commissioned by MEC has recommended a severance tax of 1.5%, although the legislature has not yet codified a new severance tax rate (Lewis-Raymond 2013). The importance of this new tax rate should be obvious. One of the primary reasons in favor of fracking is the ensuing economic benefits and the severance tax is a large determinant in the distribution of these benefits. API has distanced itself from the topic, and takes no stance on the matter of an appropriate severance tax rate. Likewise, environmental groups have understandably provided no guidance here, as the question of a proper tax rate is largely one of economics. In reality, the decision is more political in nature, the result of compromise between the industry and its state regulators. Considering everything aforementioned, however, if North Carolina does not increase the existing severance tax rate substantially, the state will forego a large potential source of revenue.

Plugging and Abandonment

Well Idle Time

“An idle well is one that is not currently producing oil or gas” (Richardson 2013). In attempt to reduce risk of damage or contamination, wells are typically only allowed to remain idle for a certain time period (Richardson 2013). Past this idle time period, a number of choices are available to operators depending on the state they're located in.

Depending on the specific state, these options may include restarting well production, conversion to a waste disposal well, temporary abandonment, or plugging and permanent abandonment (Richardson 2013). In three of the Marcellus Shale states—Pennsylvania, New York, and West Virginia—the maximum well idle time is 12 months; in Ohio, this time period ranges from 12 to 24 months (Richardson 2013). Current North Carolina law permits wells to remain idle for only one month, but MEC’s rules seek to expand this time period significantly. The proposal is that once permission is granted, a well may remain idle for one year, at the end of which annual renewal is required (15A NCAC 05H .1519). “A maximum of three renewal periods may be authorized before the well shall be placed into production or temporarily abandoned” (15A NCAC 05H .1519). Neither API nor environmental groups recommend a best practice for well idle time.

Temporary Abandonment

“Temporary abandonment is essentially a formalized way of leaving a well idle, with added safety or maintenance requirements; in most cases, it is invoked after a well has been idle for the maximum allowable time” (Richardson 2013). The additional requirements for temporary abandonment serve the purpose of mitigating the risk of damage to the well and contamination of the well. API’s best practice for temporary abandonment specifies that a well must be maintained to the extent that a routine workover operation can bring it back into production (2009a). API does not, however, recommend a time period for temporary abandonment.

In New York, temporary abandonment is permitted for three months; it is permitted for one year in Ohio and for five years in Pennsylvania (Richardson 2013). Temporary abandonment is banned altogether in West Virginia. It’s also currently

outlawed in North Carolina, but MEC's rules would make the practice valid for five years, with a maximum of one renewal (15A NCAC 05H .1520). This rule would place North Carolina amongst the states with the longest allowable time period for temporary abandonment. The maximum allowable time period for both idle and temporarily abandoned wells is used as a proxy to measure the stringency of these regulations. The time period by itself, however, does not provide an indication of either the stringency of temporary abandonment rules or the safety of those wells temporarily abandoned. With regard to this area of regulation, the condition of the well itself, and by extension the extent to which it is maintained, is of the utmost importance. Because there is no standard criterion for evaluating the condition of an idle or temporarily abandoned well, it is difficult if even possible to establish appropriate time periods for such practices.

Accident Reporting

In general, accidents at well sites including spills, leaks, fires, and blowouts must be reported promptly after their discovery. New York and Pennsylvania require accidents to be reported within two hours, while West Virginia allows up to 24 hours (Richardson 2013). Ohio does not specify a timeframe within which accidents must be reported. In North Carolina, MEC's rule proposal stipulates that spills and leaks exceeding a volume of one barrel should be reported as soon as practicable, but must be reported within 24 hours (15A NCAC 05H .1906). "API best practice is that 'a spill or leak should be promptly reported,' but 'promptly' is not defined in terms of any specific timeframe" (Richardson 2013; API 2011). Therefore, what this best practice actually means is left up to interpretation by the individual well operator.

Surface Disturbance Management

Other than construction standards (for the well site, well site infrastructure, and access roads) and reclamation requirements, MEC's rule set does not regulate surface disturbance management. As noted previously, much surface disturbance is necessary byproduct of an unconventional oil and gas industry developing the land on which it will drill. API provides guidance on surface disturbance management in their document, API Recommended Practice 51R. "The development of surface use plans will allow for more efficient use of the land while balancing protection of important local resources, by minimizing surface disturbance and mitigating those impacts that are unavoidable" (API 2009a). According to API,

Field inspections and lab analysis of soil samples may be used to assess soil erosion hazards and slope stability. Properties of soils, length and gradient of slopes, and vegetative cover contribute to soil stability. Fitting the profile to topography, locating roads on moderate slopes, providing adequate drainage, and stabilizing slopes decreases surface disturbance and reduces erosion and sedimentation (API 2009a).

API also offers suggestions for selecting a proper route for lease gathering and system lines. "Proximity to lakes, streams (including dry washes and ephemeral streams), wetlands, drainage and irrigation ditches, canals, flood plains, and shallow water wells. These features should be evaluated in terms of disturbances during construction and routine operations, and in the event of accidental releases" (API 2009a). Finally, API Recommended Practice 51R discusses the direct relation between properly managing "water resources during the development and operations phases of oil and gas production...[and] minimizing surface disturbances" (API 2009a).

Part 3: Analysis of Best Practices and Key Regulatory Issues for North Carolina

Wastewater Disposal

Given the large amount of uncertainty pertaining to the consequences of various fracking waste disposal methods, disposing of wastes from unconventional oil and gas operations poses a significant threat to the environment. The most concerning aspect of wastewater disposal is that there isn't an established standard (Goldman 2015). Across the U.S., it is most common to dispose of wastewater in underground injection wells. In North Carolina, underground injection wells for the purpose of waste disposal are banned. Dr. Rao said MEC explicitly didn't allow underground injection as an option in the rule set because MEC realized that the ban on underground injection wells might be lifted in future (Rao 2015).

The current best practice in waste disposal recommends recycling fracturing fluids by processing wastewater to remove contaminants, particularly salinity. Some operators might want to take out dissolved ions or other TDS, or add a bactericide (Rao 2015). In studies from Pennsylvania, radioactivity has also been shown to be a potentially problematic contaminant (Goldman 2015). Most companies already recycle fracturing fluids to lower the costs of wastewater disposal and future water withdrawals. Salinity is particularly important to remove because fracturing fluids are typically designed with freshwater. However, salinity treatment would be particularly minimal in NC, which is freshwater lake-based (rather than seawater based); the salinity of flowback water is expected to be less than 5000 ppm (Rao 2015). Typically, a third party treatment company comes to a well site to treat the wastewater on site (Rao 2015).

Eventually, wastewater must be disposed of once it has been treated and reused to the fullest extent possible or because there are no other nearby wells that would reuse it, if it were to first be treated. The North Carolina rules allow operators to treat it and send it to centralized waste treatment facilities, which are permitted locations and have their own regulations (Rao 2015). MEC recognizes that municipal water treatment facilities aren't designed to remove contaminants found in fracking wastewater and therefore, MEC doesn't favor municipal water facilities because they cannot accept untreated wastewater. If sent to a publicly owned treatment works (POTW), wastewater must first be treated to the satisfaction of the POTW, the specific requirements of which are denoted by DENR. "A POTW cannot stand salinity because it relies on bacteria to do its job and those bacteria do not survive high salinities" (Rao 2015). The desalinization of wastewater from unconventional oil and gas operations in NC should be very straightforward because of the low salinity expected. Wastewater must not leave the property before it has been treated to the point that it meets the standards of its final destination. Other than treatment and disposal at a POTW, North Carolina's rules also allow for the possibility of the transport of wastewater to neighboring states for deep discharge (into underground injection wells); MEC doesn't take a position on whether or not this should be done (Rao 2015).

Dr. Rao and Dr. Goldman have different visions of how NC fracking wastewater would be disposed of. Dr. Goldman believes that operators will probably export the waste to another state, to be injected in an underground injection well (Goldman 2015). The Union of Concerned Scientists (UCS) prefers whichever disposal method is least risky, as defined by the primary concern of the local community. However, Dr. Rao said, "More

than likely, the kind of operations we'll see in NC (if any at all) would use a centralized waste treatment facility, which would then treat it to the point where something could be done with it" (Rao 2015). If someone were to design a wastewater treatment plant for fracking waste, it would have to be very specialized for this purpose (Goldman 2015).

The implication is that wastewater from unconventional oil and gas operations in NC would be disposed of using one of two imperfect methods. The first option, underground injection, would necessitate the transportation of the wastewater outside of NC. The second option, preliminary treatment, followed by treatment in a POTW, also has issues. There are no wastewater treatment facilities in NC designed to remove the host of contaminants found in fracking wastewater, so waste would either be sent through an existing POTW within the state or transported outside NC to another treatment facility. Both methods of disposal involve the transfer of wastewater outside of NC which, rather than providing an actual solution, delegates the problem to another state. The best practice for wastewater disposal, though not yet realized, would likely consist of a pre-treatment of fracking wastewater performed on site followed by secondary treatment at a facility specifically designed to remove the aforementioned contaminants. What regulations and/or incentives would force the establishment of this proposed best practice is another issue altogether.

Presumptive Liability and Baseline/Subsequent Testing

North Carolina law includes a provision of presumptive liability that predates the state's drafting of the rule set regulating fracking. According to NC Gen Stat § 113-421 (2013),

If a contaminated water supply is located within 5,000 feet of a wellhead, in addition to any other remedy available at law or in equity, including payment of compensation for damage to a water supply, the developer or operator shall provide a replacement water supply to the surface owner and other persons using the water supply at the time the oil or gas developer's activities were commenced on the property, which water supply shall be adequate in quality and quantity for those persons' use (N.C.G.S. § 113-421) .

North Carolina's fracking regulations will also require comprehensive environmental testing. Section .1700 of 15A NCAC 05H sets out the requirements for pre-drilling testing of water supplies, testing of water after production has begun, and reporting of data collected from proposed well sites.

The majority of states do not require pre-drilling water testing (Richardson). Of the states that do require baseline testing, Colorado has the most stringent rule, which stipulates all bodies of water within a half-mile of well sites must be tested (Richardson). The remainder of these states require baseline testing of waters within a smaller distance from the well site. Pennsylvania is the only state that uses a burden-shifting presumptive liability rule instead of requiring pre-drilling water testing (Richardson).

North Carolina is unique in that it is the only state that makes use of both baseline testing requirements and a presumptive liability provision. While employing both of these two alternatives may seem redundant, it is not; rather, the two are complimentary. First, operators in North Carolina are required to perform a series of water tests, before and after drilling begins, until all permitted wells on a well pad are completed. These data are collected and reported to DENR, "...Director of the local health department, surface owner(s), and owner(s) of the water supply within 30 calendar days of receipt of analytical results" (15A NCAC 05H .1706). If subsequent tests find initially clean water

to later be contaminated, the presumptive liability clause takes effect, making the well operator liable for the water contamination and consequent damages. Presumptive liability places the burden of proof on the well operator rather than on the party whose water source has been contaminated. This is crucially important (per the polluter-pays principle) and because of the resource disparity between well operators and affected water consumers. UCS emphasizes the importance of baseline testing being comprehensive, ongoing, publicly accessible, and available in a timely manner and so, commends North Carolina's regulations in this area (Goldman 2015). North Carolina's unique combination of both command and control (required baseline testing) and burden shifting (presumptive liability) regulations will soon set a new standard in best practices for environmental, and specifically water, testing. Furthermore, North Carolina's rule set includes a provision that makes possible the use of tracer technology, which, while still in early stages of implementation, may very well be the future in environmental testing.

Standards in Well Construction and Maintenance

It is undeniable that proper construction, inspection, and maintenance of wells are paramount to prevent potential contamination of USDW. Dr. Rao, citing a recent paper from researchers at Duke University, expressed his view that “proper well construction is the total key to preventing accidental contamination” (Rao 2015). He believes that any contamination would not be coming from the fracturing zone, but rather from improper well construction (Rao 2015). “This is also what MEC believes as a commission, so most of their efforts have been spent on writing rules so that the wells are properly constructed and can be inspected” (Rao 2015). UCS conveys a similar viewpoint: “In most places, it is likely that the risks of groundwater contamination largely can be minimized by best

engineering management practices such as stronger and deeper steel casing, thorough cementing, adequate drilling mud removal, and appropriate geological and well integrity monitoring” (Goldman 2013).

Best practices for well construction and maintenance are established in guidance documents published by API. No other organization provides such best practice standards for well construction. Thus, engineers within the industry necessarily set current best practices for well construction and maintenance. Given that industry engineers are the only people actually designing and building these wells, this result is not surprising. They are the only group of people who have experience and authority in this highly technical matter. North Carolina’s well construction regulations frequently reference technical standards set out in API guidance documents.

It is somewhat troubling that only the oil and gas industry weighs in on best practices in this area, given how important well construction standards are in protecting USDW from contamination. Dr. Goldman argues that engineers in academia with a similar working knowledge of well design should weigh in here. A scientific society (e.g. American Association of Petroleum Geologists or American Society for Testing and Materials) comprised of academic and industry engineers should at least evaluate API’s standards, if not provide their own (Goldman 2015). American Society for Testing and Materials (ASTM) already has cement standards in place and North Carolina’s rule set references “C150/C150M Standard Specification for Portland Cement” (15A NCAC 05H .1509). ASTM or another scientific society should aim to establish standards for other parts of well construction. A scientific society’s standards would not be biased in the way

that API's standards might be, for the goal of the society would not be directly tied to the profits of the oil and gas industry or any particular companies within it.

Chemical Disclosure and Trade Secrets

This section explores North Carolina's chemical disclosure and trade secret rules in detail and compares them to the current best practices in disclosure regulations, using Alaska's newly revised rules as a case study. Telephone interviews with Dr. Vikram Rao, current chairman of North Carolina's MEC and former Chief Technology Officer at Halliburton, and Dr. Gretchen Goldman, lead analyst and point person on fracking (FY 2015) at The Union of Concerned Scientists' (UCS) Center for Science and Democracy, provide different, but relevant perspectives on the current state of North Carolina's disclosure rules, the future direction of chemical disclosure, and the ideal balance between protecting trade secrets, the environment, and public health. Finally, regulations pertaining to prohibited substances are addressed, with particular focus on BTEX compounds and the role of oil and gas companies' discretion over fracking fluid disclosure and composition.

Standards in disclosure of chemicals used in fracking fluids are highly controversial, dynamic, and variable across states. The majority [of states] (19), including all the major gas-producing states, have rules proposed or in place. Given the relatively recent emergence of large-scale hydraulic fracturing, this indicates a relatively rapid pace of regulatory change. It is possible, therefore, that the states without disclosure requirements will follow the lead of the major producers and implement such rules as their drilling and production activity increases (Richardson 2013).

North Carolina has indeed followed the lead of other states with larger production capacities and longer histories of unconventional oil and gas development in developing

rules of its own, particularly with regard to chemical disclosure. “All states with chemical disclosure requirements provide trade secret exemptions for chemicals considered ‘confidential business information’” and, as mentioned previously, trade secret exemptions are the most contentious aspect of chemical disclosure (Richardson 2013). The World Intellectual Property Organization (WIPO) asserts, “...Any confidential business information which provides an enterprise a competitive edge may be considered a trade secret. Trade secrets encompass manufacturing or industrial secrets and commercial secrets” (WIPO 2015). Trade secrets are similar to patents in that their primary purpose is to protect firms’ unique competitive advantages.

North Carolina’s rule set matches this standard practice with its own provisions for trade secret exemptions. Trade secret protection in fracking chemical disclosures is explained by 15A NCAC 05H .1604. According to Section (a), “the permittee, vendor, or service company is not required to disclose trade secrets, as defined by G. S. 66-152(3), except as otherwise required in this Section” (15A NCAC 05H .1604).

As defined by N.C.G.S. 66-152(3),

"Trade secret" means business or technical information, including but not limited to a formula, pattern, program, device, compilation of information, method, technique, or process that:

- a. Derives independent actual or potential commercial value from not being generally known or readily ascertainable through independent development or reverse engineering by persons who can obtain economic value from its disclosure or use; and
- b. Is the subject of efforts that are reasonable under the circumstances to maintain its secrecy.

The existence of a trade secret shall not be negated merely because the information comprising the trade secret has also been developed, used, or owned independently by more than one person, or licensed to other persons. (1981, c. 890, s. 1.)

Section (b) of 15A NCAC 05H .1604 delineates the reporting requirements for fluid additives and/or chemical ingredients claimed to be trade secrets:

For a chemical name or CAS registry number to be eligible for trade secret protection, the permittee, vendor, or service company shall provide the following information for Departmental consideration:

(1) the manufacturer's name, trade or common name of the chemical, CAS registry number, the chemical's hazard class and category (if applicable), and the common name or other similar description associated with each chemical contained in the additive or mixture;

(2) the justification for the trade secret claim for each chemical, additive, or mixture to be protected from public disclosure, said justification including an affidavit with each of the following elements:

(i) a stipulation that the trade secret information is not in the public domain, including in published patent applications;

(ii) evidence that the information has been treated in the same manner as other trade secrets in the company, said manner being detailed in the affidavit;

(iii) agreement to notify the Department if said information loses trade secret status;

(iv) certification that the chemical for which trade secret protection is sought is not regulated under the Federal Safe Drinking Water Act's National Primary Drinking Water Standards or National Secondary Drinking Water Standards, including subsequent amendments and editions, or if regulated is not present in

concentrations greater than the EPA-listed maximum contaminant level for that chemical; and

(v) certification and evidence that the chemical for which trade secret protection is sought meets the definition of a trade secret under the N.C. Trade Secrets Protection Act in N.C.G.S. § 66-152(3), including that the chemical is not “generally known or readily ascertainable through independent development or reverse engineering by persons who can obtain economic value from its disclosure or use.”

(3) a publicly releasable Safety Data Sheet for each chemical, additive, or mixture of chemicals, containing relevant information about the properties and effects of the substance or mixture and handling instructions;

(4) business contact information, including the company name, name of authorized representative, mailing address, and phone number for the business organization claiming entitlement to trade secret protection on Form 20- Trade Secret Claim; and

(5) emergency contact information including the office name and telephone number of individuals who have 24-hour, 7-day access to the trade secret information and who can reliably be reached at any date and time ” (15A NCAC 05H .1604).

15A NCAC 05H .1604 Section (e) states that unless protected as a trade secret, all information submitted to DENR or uploaded to FracFocus is public information (15A NCAC 05H .1604).

A comparison of state chemical disclosure/trade secret regulations across the U.S. shows Alaska’s recently revised regulations as a model for current best practice. “In December 2012, the Alaska Oil and Gas Conservation Commission (AOGCC), Alaska’s state regulator of oil and gas operations, proposed new rules for hydraulic fracturing with a chemical disclosure requirement that did not contain any exemption for trade secrets”

(Goldman 2013). Were it to become law, it would have been "...the first chemical disclosure law in the nation, federal or state, without a trade secrets provision" (Goldman 2013). Cathy Forester of the AOGCC, who led the effort on developing the new regulations, said the commission intentionally omitted a trade secret exemption clause (Gilmer 2013). On behalf of the AOGCC, Forester invited the oil and gas companies to a series of public hearings if they wished to advocate for the inclusion of a trade secret provision in the revised rules (Gilmer 2013). Reuters reported, "Industry representatives complained at the [September 23, 2013] hearing and in written testimony that the proposed Alaska fracking regulations are stricter than those in place or proposed in other states. They objected to the specific chemical disclosures because they would reveal proprietary formulas and trade secrets" (Rosen 2013). The industry's success in lobbying AOGCC to include a trade secret provision in the rule set is evident in AOGCC's revised hydraulic fracturing regulations, which "...will appear in Register 213, April 2015, of the Alaska Administrative Code" (AOGCC 2014). Although operators in Alaska will be allowed to claim some chemicals as trade secrets and therefore, exempt those chemicals from disclosure requirements, AOGCC's new regulations made meaningful strides in strengthening both the burden of proof placed on the operators claiming trade secrets and the review process that ostensible trade secret chemicals are subject to. 20 AAC 25.283 Section (k) states, "Any information...the filing party believes to be a confidential trade secret shall be separately filed in an envelope clearly marked "confidential" along with a list of the documents that the party believes to be wholly or partially nondisclosable as trade secrets, and the specific legal authority and specific facts supporting nondisclosure" (20 AAC 25.28). Under the Alaska Public Records Act, requests can be made for the

disclosure of information claimed as confidential. Section (k) of 20 AAC 25.283 goes on to set out a legal process for determining “...whether to provide the party making the public records request the requested documents or the list of nondisclosable documents, the specific legal authority and facts supporting nondisclosure, and the affidavit provided by the party claiming confidentiality” (20 AAC 25.28).

Absent from the most current North Carolina rule set is a provision allowing for the challenging of trade secret status. An earlier version of the rules contained such a provision, which could have been expected to operate similarly to that of Alaska. The relevant part of the earlier version of North Carolina’s rule set read:

A Landowner, an owner of Adjacent Property, a lessee of any property on which a wellhead is located, any person having a legal interest in real property, or agency of this state having an interest that is or may be adversely affected by a product, fluid or substance or by a chemical component in a product, fluid or substance may submit a request challenging a claim of entitlement to trade protection for any chemical ingredients and/or CAS numbers used in hydraulic fracturing treatment(s) of a well (15A NCAC 05H .0XX6).

The North Carolina Business Court would then have to determine whether to disclose the information to the requestor or whether the information remains entitled to trade secret protection (15A NCAC 05H .0XX6). The rule also laid out an appeals process. Here, North Carolina missed out on an opportunity to follow Alaska’s lead in providing a mechanism for trade secret challenges and establish a new best practice in this particular area of chemical disclosure regulations.

In another area, the details of North Carolina’s proposed chemical disclosure requirements and trade secret provisions strongly resemble a key place where Alaska

recently improved its rule set. Like Alaska, North Carolina requires supporting legal evidence for all trade secret claims. Dr. Rao, chairman of MEC, elaborated on the rules, “What I’m asking for is relatively simple: an affidavit, no in-person interview” (Rao 2015). MEC got a lot of pushback from some people within the industry who said the proposed requirements are onerous. Given his extensive experience within the industry, Dr. Rao feels he knows what can be demanded of the companies without being onerous, but still being sufficient. “Among other things, the MEC needs a company to certify an affidavit that they’ve never publicly disclosed it to anyone...which effectively disqualifies many chemicals. It puts them on their honor because they have to say certain things under oath” (Rao 2015). In Dr. Rao’s opinion, it’s not asking a lot, but it’ll reduce the list of trade secret chemicals substantially. “This [affidavit] requirement could be expected to limit the exclusion claims to genuine trade secrets (Rao 2014).

In his blog, as executive director of Research Triangle Energy Consortium (RTEC), Dr. Rao expands upon how the trade secret provision would be applied in practice, and in particular, how to determine which chemicals will qualify:

Virtually all service companies use some variant of these very chemicals. There is no pressing need for substitution of these with others except to make them greener. The trade secret exclusion would apply only to substitutes with use advantages. Such a claim will be very hard to substantiate in shale gas wells; the standard chemicals work just fine (Rao 2014).

Although North Carolina’s rule set allows for specific chemical ingredients and/or their CAS numbers to be claimed as trade secrets, Dr. Rao argues that the industry’s standard chemicals would not qualify and neither would substitute chemicals that lacked use advantages over the standard chemicals they were designed to replace (Rao 2014).

According to Dr. Rao, innovative substitute chemicals will carry one of two types of use advantages: environmental or one related to recovery efficiency (Rao 2014). “To the extent the secret is in the green chemical ingredient, it ought to receive trade secret status after some verification” (Rao 2014). While the invention of greener chemicals may result from concerns of corporate image, financial liability in case of accidents, etc., chemical advancements to increase the recovery of gas and oil will likely come about as a result of market forces. One of the places in which the industry will be forced to innovate due to declining oil prices is in recovering a higher fraction of the hydrocarbon than is recovered at present (Rao 2015). According to Dr. Rao, the industry currently recovers about 25% of gas, which, through chemical and technological advances, can be expected to increase to about 50%; the current figures for oil recovery are near 5%, which can be expected to increase to 15% (Rao 2015). “But the improvements [in recovery efficiency] must not compromise the environment or public health. Full disclosure of the CAS numbers for substitutes ought to be the goal” (Rao 2014).

Therefore, under Dr. Rao’s interpretation of the rules, the only individual chemicals that would qualify for trade secret exemptions would be new, innovative chemicals with either a recovery efficiency or environmental use advantage. To the extent that this interpretation of the trade secret provision is applied in practice, North Carolina will be following the current best practice in regulations pertaining to trade secret exemptions, with the small exception of having no legal process for challenging trade secrets. However, Dr. Rao believes that we should aim for the full disclosure of CAS numbers of all substitute chemicals with a use advantage type other than being

“greener” (less harmful to the environment and/or public health) without affording them the protection of trade secret status.

Greener chemicals are desirable and innovation in this area ought to be granted trade secret status...but since by their very nature these ingredients will be environmentally benign, the secrecy will almost certainly be in the recipe...To the extent the secret is in the green chemical ingredient, it ought to receive trade secret status after some verification (Rao 2014).

Dr. Rao’s proposition of allowing trade secrets only for “greener” chemicals falls short of full disclosure, but is still stronger than North Carolina’s current chemical disclosure rules which, as mentioned above, are among those setting the current best practice for state-required chemical disclosure in the U.S.

Dr. Goldman said North Carolina’s chemical disclosure rules are among the better disclosure regulations she’s seen and that the only higher level of disclosure would be the prohibition of trade secrets, as was recently proposed in Alaska. UCS advocates for full disclosure of wastewater composition in addition to full disclosure of all chemicals in fracking fluids without any trade secret exemptions. Their 2013 report on fracking conveys this position:

The chemical composition, volume, and concentration of all hydraulic fracturing fluids used in each specific locality should be disclosed, including chemicals considered proprietary; this information should be made available to the public online before drilling can begin. Further, the chemical composition of flowback and other wastewater in every locality should be publicly disclosed. Public safety should be prioritized over company trade secrets, as it has been for other regulated industries (Goldman 2013).

If chemical disclosure, and particularly trade secret, rules continue to become more

stringent largely in response to public awareness of fracking activities and related PR concerns of companies, eventually moving to UCS's desired full disclosure without any trade secret provisions, the path to full disclosure will be interesting to observe. Dr. Rao has already demonstrated one way to find a step between North Carolina's current rules and full disclosure; many similar ideas will likely arise in the near future. Other states that either lack disclosure requirements altogether or have much more lenient disclosure regulations may find many such steps between their current rules and full disclosure. Because North Carolina's rules are already so strong, there is less room for intermediary steps between the rules in their current form and full disclosure. Therefore, any partial step toward full disclosure would likely be similar to Dr. Rao's proposition in that it would work by way of increased specificity in revision of statutory language.

In March 2014, a collective of oil and gas associations (referred to as "The Associations"), including American Petroleum Institute ("API"), American's Natural Gas Alliance ("ANGA"), the Independent Petroleum Association of America ("IPAA"), and the American Exploration & Production Council ("AXPC"), wrote, "...to comment on the Secretary of Energy Advisory Board's FracFocus 2.0 Task Force Report Draft" (Milito 2014). Their letter reads, in part,

The Associations strongly support and promote full disclosure of chemical ingredients intentionally added to hydraulic fracturing fluids, with recognition of legitimate claims for protection of intellectual property under applicable laws. The oil and gas industry has furthered the goals of transparency and public disclosure by backing the use of the voluntary disclosure registry, Fracfocus.org (Milito 2014).

Joint comments made by The Associations clearly convey the industry's stance on trade secret protection. "A company's trade secrets can be among its most important assets --

the key intellectual property that allows it to keep its market position for its products or services and provide value to its shareholders” (Milito 2014).

One crucial distinction to make with regard to trade secret exemptions is between awarding trade secret protection to recipes (or formulas) versus individual ingredients. There is a logical and compelling argument to be made for awarding trade secret protection to chemical formulas or recipes, while requiring the disclosure of all component ingredients. This discussion is analogous to the trade secret protection Coca-Cola’s formula enjoys, while the ingredients of the soda are printed on each and every can. “The use of standard chemicals allows for high quality shale gas wells. Companies are becoming increasingly open on this point because of public concern with non-disclosure” (Rao 2014). For example, Halliburton’s website lists the precise additives it uses in fracking fluids across various shale formations within the U.S., as well as the percentage each additive accounts for in the fluid and the chemical constituents of each additive, including CAS number (Halliburton 2014). If all component ingredients were to be fully disclosed, then non-disclosure of the formula “...is not an issue because the proportions of what went into the ground are not terribly relevant. What goes in is not what comes out. Some constituents are consumed, such as biocides, some are partly reacted and some return in the form introduced” (Rao 2014). Instead of concerning ourselves with the proportions of chemicals found in the fracking fluid, Dr. Rao suggests researchers redirect their efforts to studying flowback water to learn more about the composition of both wastewater and of the fluid that remains underground (Rao 2014). Currently, the composition of wastewater is not disclosed at all and it is often recycled or

disposed of without ever undergoing a chemical test. UCS explains why this information gap is troublesome:

The rules have no requirement to disclose the chemical contents of the wastewater—both flowback and produced water—that comes back out of wells, leaving the public to guess its composition based on the company’s incomplete disclosures of the chemicals that were originally put into the well... Thus, the public would have no information about the salinity, radioactivity, or concentration of other hazardous substances present in the wastewater (Goldman 2013).

Dr. Goldman and Dr. Rao agree that disclosure of wastewater is critically important. Given that chemical analysis of wastewater provides a more accurate depiction of both what remains underground and what comes back up and that at present, its chemical composition isn’t a required disclosure, wastewater disclosure may very well be the future of chemical disclosure in fracking operations. If wastewater composition and all chemical ingredients of fracking fluids were required full disclosures (without trade secrets), companies could keep trade secret protections for the formulas of their fracking fluids. The volume and concentration of each fracking fluid chemical wouldn’t need to be disclosed because a comprehensive chemical analysis would be performed on both flowback and produced water. Therefore, information about the composition of the fluids both resurfacing and remaining underground would increase drastically, while still allowing companies to keep their fracking fluid recipes as trade secrets.

Regarding the parties to whom chemical information is disclosed and the time frame for disclosure, North Carolina’s rules provide for timely and accessible disclosures. “The permittee shall notify the local emergency management office of all hazardous chemicals that may be used for any purpose at the well site no later than 30 days prior to

the chemicals entering the well site” (15A NCAC 05H .1603). Similarly, “The permittee, service company, or vender shall submit to the Department, no less than 30 days prior to the commencement of well stimulation activities, a complete list of all base fluids and additives to be used in well stimulation activities” (15A NCAC 05H .1603). Both DENR and first responders will receive disclosure well in advance of the actual hydraulic fracturing process, which should allow them ample time to plan for emergency situations. Once the fracturing has taken place, the permittee must “upload all well stimulation data...to the FracFocus website and submit a...Chemical Disclosure Report to the Department within 15 days following the conclusion of well stimulation” (15A NCAC 05H .1603). The public (via FracFocus) is the last party to receive disclosure and receives information about what chemicals were in fact used in the well rather than those that were planned for use before well stimulation actually began. Although North Carolina’s disclosure rules fall short of UCS’s assertion that chemical disclosures should be made publicly available online before drilling begins, they are currently among the most timely and accessible disclosure regulations in the U.S. Moreover, accurate disclosure information, especially pertaining to chemical quantities and concentrations (as opposed to chemical names or CAS numbers), may not be available until after well stimulation concludes; any such information disclosed before well stimulation commences is likely nothing more than an informed estimate.

In the case of a spill or release,

A permittee, vendor, or service company shall identify the specific chemical identity, CAS registry numbers, amounts, and concentrations for any chemicals or additives claimed to be a trade secret to the Department upon receipt of a...request from the

Secretary...Such information shall be disclosed...as soon as possible, but in no case more than two hours following the Secretary's request (15A NCAC 005H .1606).

The two-hour time frame is also in effect for trade secret disclosure to health professionals and emergency responders. However, health professionals and emergency responders are subject to a confidentiality agreement and must provide a written statement of need before receiving such disclosure (15A NCAC 005H .1606). The written statement of need must conform to one of two criteria. Specifically, it must be the case that either “the information is needed for purposes of diagnosis or treatment of an individual, the individual being diagnosed or treated may have been exposed to the chemical concerned, and knowledge of the information will assist in such diagnosis or treatment” or “the information is needed for the purpose of emergency management, coordination or response and recovery, following an emergency and knowledge of the information will assist in the response and recovery” (15A NCAC 005H .1606). This two-hour time frame should allow for relatively quick response to emergencies, while still providing a reasonable amount of time for operators to respond. However, there can be tension between the protection of trade secrets and the ability of health professionals to diagnose and treat patients exposed to trade secret chemicals. For example:

Doctors in Pennsylvania have spoken of their own hesitation, delays, or nervousness in requesting information from companies, because of their uncertainty about the law's implications and associated legal requirements and their fear of adverse consequences from oil and gas companies. As a result, some doctors have reported being unable to provide their patients with full and proper care (Goldman 2013).

There is not yet a clear answer on how to resolve this tension. Considering that currently, there is no established, proper protocol in cases of spills or releases, the emergency

disclosure provisions in North Carolina's chemical disclosure/trade secret rules are among the strongest in existence.

Oil and gas companies are beginning to play an increasingly important role in leveraging their bargaining power to influence the level of disclosure and the composition of the fluid used by service providers in hydraulic fracturing jobs performed at their well sites.

Without exception the trade secret exclusions are sought by the service company or a supplier to them, not the oil and gas company who will use the products in the well completion process. In many cases the oil company is in the dark regarding the precise formulation. But increasingly the medium to larger oil companies are asserting their purchase power rights to demand fuller disclosure (Rao 2014).

Dr. Rao explained why it is the service companies, rather than the oil and gas companies, who prepare the fracking fluid. "There are many small operators without any domain understanding in this area, so the service company walks in and says 'Our recipe works the best.' There used to be just 4 or 5 major service companies, but now there are at least 50 smaller ones as well, many of them with differing amounts of real expertise" (Rao 2015). According to their website, Baker Hughes, one of the major providers of hydraulic fracturing services in the U.S., now provides "...A complete, detailed, and public listing of all chemical constituents for all wells that the company fractures using its hydraulic fracturing fluid products" (Baker Hughes 2014). A spokesperson for Baker Hughes confirmed that the company's new chemical disclosure policy does not include exemptions for trade secrets (Soraghan 2014). Well operators' need for disclosure of fracking fluid composition is especially strong in North Carolina where the operator is required to disclose chemical information to other parties, such as DENR and in the case

of accidents, health professionals and emergency responders. “Oil and gas companies have a lot of choice when it comes to service providers and ought to be discerning on this point...oil and gas companies ought to strive to employ only those service companies prepared to fully disclose the chemicals used, including the CAS numbers of each” (Rao 2014).

Beyond demanding full disclosure from service companies, large oil and gas companies can go further by pressuring the service companies to omit certain substances from the fracking fluid altogether and there is precedent. Apache Corporation, a multi-billion dollar, multinational oil and gas company, “...now requires the ‘elimination of diesel, BT[E]X, endocrine disruptors, and carcinogens’ as constituents in fracturing fluid. This is important because service companies know that the customer has choice. This is especially so in shale gas operations, which use ‘slick water’ formulations containing fewer chemicals” (Rao 2014). Apache Corporation’s outright ban on BTEX chemicals in fracking fluid is an area where this company has enacted stricter rules than any state government. “Rarely, states regulate fracturing fluids beyond mere disclosure. Wyoming, for example, requires prior approval for use of benzene, toluene, ethylbenzene, and xylene (BTEX) compounds” (Richardson 2013). Wyoming’s requirement of prior approval for the use of BTEX compounds falls far short of Apache Corporation’s explicit ban and Wyoming has been considered a model state for strong rules on fracking (Galbraith 2013). James Womack, former chairman of MEC, spoke about prohibited chemicals and constituents in North Carolina and specifically the potential use of BTEX compounds in fracturing fluids. ““It is my understanding our banned chemicals rule prohibits use of BTEX chemicals given that they are derivatives of diesel,’ says Womack.

‘We are checking into this and we may consider modifications to the rule to clarify for the public that use of BTEX chemicals are clearly banned in North Carolina’” (Wallace 2014). Upon closer inspection of the rules, however, it is clear that BTEX compounds are not among the list of banned chemicals for use in fracking fluids in North Carolina. The “Prohibited Chemicals and Constituents” section of the rules states:

Any substance identified with one or more of the following Chemical Abstract Service Registry Numbers listed in the United States Environmental Protection Agency’s “Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels” shall not be used in the subsurface:

- (1) 68334-30-5 Primary Name: Fuels, diesel
- (2) 68476-34-6 Primary Name: Fuels, diesel, Number 2
- (3) 68476-30-2 Primary Name: Fuel oil Number 2
- (4) 68476-31-3 Primary Name: Fuel oil, Number 4
- (5) 8008-20-6 Primary Name: Kerosene
- (6) 68410-00-4 Primary Name: Distillates (petroleum), crude oil (15A NCAC 05H .1507).

None of the BTEX compounds are mentioned by name and furthermore, because none of the above CAS numbers match any of the four BTEX compounds, the BTEX compounds are certainly not prohibited. Given that the status of the “Prohibited Chemicals and Constituents” subsection of North Carolina’s rules is “completed,” it is doubtful that MEC is still considering a modification of the rules to “clarify for the public that use of BTEX chemicals are clearly banned in North Carolina” (N.C. DENR 2014).

Framework of Fees and Taxes

An unconventional oil and gas industry in North Carolina will incur a host of costs on a number of different parties. To ensure that these costs are appropriately paid for and do not become externalities, they must be categorized and addressed according to who bears them. A study group, consisting of representatives from MEC, DENR, N.C. Department of Transportation (NCDOT), N.C. League of Municipalities (NCLM), and N.C. Association of County Commissioners (NCACC), was commissioned for this purpose in September 2013 (Lewis-Raymond 2013). “The Study Group spent considerable time over the course of eleven meetings determining the potential costs and identifying the potential sources of funding to adequately fund the costs associated with developing and implementing a modern oil and gas industry in North Carolina” (Lewis-Raymond 2013). The North Carolina legislature has yet to codify the Study Group’s recommendations into law. The recommendations are divided into four categories.

First, the study group is concerned with costs accruing to local governments. The study group expects these local costs to be associated with:

- Transportation infrastructure upgrades & repair;
- Waste handling;
- Hazmat training;
- Emergency response;
- Training of local government staff – tax assessors, registers of deeds, inspectors/code compliance officers;
- Increase in local government personnel or overtime needed – tax assessors, registers of deeds, well testers, inspectors/code compliance officers;
- Drinking water well testing; and

- Increase in local government personnel or overtime needed – tax and transportation assessors, registers of deeds, well testers, inspectors/code compliance officers, public safety officers (Lewis-Raymond 2013).

To recover these costs (other than transportation infrastructure) for local governments, “the Study Group recommends that a permittee be required to pay an impact fee that comports with the level of industrial activity for a given well” (Lewis-Raymond 2013). The impact fee is split into two parts. “The first part of the fee is designed to recover the local costs that may rise simply by virtue of the fact that the well is being drilled; while the second part of the fee is designed to recover local costs that may vary based on the number of fracturing stages in a given well” (Lewis-Raymond 2013). Specifically, the two parts of the impact fee are “1) An initial flat fee of \$2,000 for the development of each well pad; and 2) A second fee of \$1,800 multiplied by the number of hydraulic fracturing stages per each wellbore on a given pad” (Lewis-Raymond 2013). The Study Group decided to calculate impact fees based on “the number of fracturing stages per well because of the correlation between fracturing stages and local activity or ‘truck trips’; the more stages per well, the more time the well takes to be fully operational, thus the more overall activity in the local area due to projected ‘truck trips’” (Lewis-Raymond 2013). There is also the matter of how local governments will apply for and receive monies from these impact fees. The Study Group’s recommendation provides that “the impact fees would be paid into a state trust fund from which impacted entities could apply for disbursement” (Lewis-Raymond 2013).

Regarding local transportation infrastructure costs, the report claims,

In North Carolina, impacts and damages to local government transportation infrastructure from hydraulic fracturing activities will be experienced heavily by municipalities... To

most adequately recover the costs of repairs to municipal transportation infrastructure, NCLM proposes, and the Study Group is recommending, a bond and permit system modeled after the one in Pennsylvania (Lewis-Raymond 2013).

To receive an overweight vehicle(s) permit for a weigh-limit-posted municipal road, “a company would enter into an Excess Maintenance Agreement (EMA) with the municipality, under which it would agree to pay for any maintenance or restoration of a posted road that it traveled that was in excess of normal maintenance” (Lewis-Raymond 2013).

The Study Group also suggested a severance tax rate and made a recommendation as to what costs it should be used to pay for.

The Study Group recommends that a severance tax be used to fund the direct costs to the State for implementing and overseeing an active oil and gas regulatory program. These total estimated costs for the Department of Environment and Natural Resources are expected to be approximately \$1.6-1.9 million annually. The costs for the Department of Transportation are estimated to be approximately \$70,000 to nearly \$1 million per year, depending on the estimated level of natural gas production activity in the state (Lewis-Raymond 2013).

Furthermore, regarding severance taxing, the Study Group asked the legislature to consider four tenants.

1. Any severance tax should be based on computed market values, not merely the volume of product being produced;
2. The severance tax should be sufficient to fund NCDOT and NCDENR work related to the oil and gas industry;
3. North Carolina should have a simple severance tax structure; and

4. North Carolina should structure its severance tax to be competitive with other states so that industry is not discouraged from developing North Carolina's oil and gas resources (Lewis-Raymond 2013).

The Study Group recommended a severance tax rate of 1.5% of the market value of extracted natural gas in addition to recognizing “the contribution from the existing state severance tax of 5% on the value of produced natural gas liquids and recommend[ing] no change to this severance tax” (Lewis-Raymond 2013). Therefore, if the recommendation is codified by the legislature, North Carolina will have a 1.5% severance tax on natural gas and a 5% severance tax on natural gas liquids. “Additionally, a statutory fee of \$3,000 for well-permit applications currently exists and the Study Group recommends no change to this fee” (Lewis-Raymond 2013).

Finally, the report addresses bonding. “The Study Group recommends a comprehensive bonding program to consist of the following types of required bonds: a surface owner bond, geophysical exploration bond, well plugging and abandonment bond, and a site reclamation bond” (Lewis-Raymond 2013). The surface owner bond “is to provide compensation for damages to a water supply, personal property, and to market resources such as timber, livestock, and crops” (Lewis-Raymond 2013). The Study Group recommended that such bond protection for landowners should be addressed on a case-by-case basis in the lease negotiations between a landowner and a well operator (Lewis-Raymond 2013). “Overall, geophysical bonding addresses two primary classifications, designated as explosive and non-explosive exploration...The recommendation...is that a blanket bond of \$50,000 be provided by any person or company seeking to perform geophysical exploration involving explosive charges or...similar techniques in...North

Carolina (Lewis-Raymond 2013). The report goes on to discuss bonding for plugging, cementing, and abandoning wells.

Currently under § 113-378 an operator is required to submit a bond in the amount of \$5,000, plus \$1.00 for each linear foot proposed to be drilled for the well...Based on a cost estimate provided by Halliburton Corporation, the Study Group recommends a bonding amount of \$27.00 per foot of wellbore that will be filled with cement in accordance with North Carolina well abandonment rules (Lewis-Raymond 2013).

The last bond type recommended by the Study Group is site reclamation bonding. The Study Group suggested that MEC adopt a table for calculating the site reclamation bond similar to the table currently used by the Mining Section of DEMLR to determine bonding amounts for mining (Lewis-Raymond 2013).

UCS thinks it very prudent of North Carolina to be proactively thinking about how to internalize the variety of costs imposed by an unconventional oil and gas industry so they don't become externalities (Goldman 2015). In such boom-and-bust type industries, it is important to leverage funds from fees and taxes in the earlier, more lucrative years when industry revenues are highest (Goldman 2015). The structure of payments recommended by this study group seems to adequately address this concern (Goldman 2015).

Conclusions and Recommendations for North Carolina

In most areas of hydraulic fracturing regulation, North Carolina is at the forefront in meeting, and in some cases setting, current and emerging best practices. Key areas of regulation in which North Carolina's rule set does an excellent job include chemical disclosure/trade secrets, presumptive liability and baseline/subsequent testing, well construction and maintenance, setback requirements, wastewater storage, and accident

reporting. Although North Carolina's chemical disclosure/trade secret rules are, at present, among the strongest in the country, they still fall short of full disclosure and, given the transitory nature of best practice in chemical disclosure regulations, North Carolina's rules could become comparatively weak in the very near future. Additionally, North Carolina has shown commendable foresight in the recommendations advanced by the Study Group on the framework of fees and taxes. The regulations pertaining to water withdrawals are satisfactory, but could be improved by implementing a more advanced permitting system similar to Pennsylvania's where ecosystem models provide the basis for accepting or rejecting water withdrawal permits.

While North Carolina does well overall in the areas of regulation MEC has written rules for, it is not yet time to open North Carolina to unconventional oil and gas development. Crucially, North Carolina cannot responsibly allow fracking operations to commence within the state until a best practice for wastewater disposal is both well established and codified. In absence of a specified best practice for wastewater disposal, fracking operations in North Carolina would likely treat and recycle the wastewater to the extent possible, then truck it outside the state where it would be injected into a deep underground injection well or, alternatively, sent to a centralized treatment facility, then discharged to surface waters.

MEC and EMC should continue to study air pollution caused by unconventional oil and gas operations, using their findings to determine whether additional air quality regulations are warranted before unconventional oil and gas projects start in North Carolina. Sufficient time should be allowed for proper evaluation of the effectiveness of the EPA's green completion rule in regulating the host of air pollutants emitted by

fracking operations. Only then will regulators know whether it can function as a stand-alone air pollution rule or, alternatively, if the green completion rule isn't comprehensive enough without supplementary, state-level regulation of air emissions from fracking.

Further scientific studies on the hydro-geological dynamics of North Carolina's Triassic Basin subsurface should be conducted in order to quantify the increase in risk of groundwater contamination due to the atypically small vertical separation between water supply wells and gas-containing shale formations. The gas-water separation distance is one-half to one-fourth of the separation distance in the Marcellus Shale area (PSPB 2014, Smith 2012). If the studies show that North Carolina's water and gas deposits are located too close to each other for fracking to be done without entailing an unacceptable level of risk, the state should close its land to unconventional oil and gas development, at least until the advent of a technological breakthrough in the fracking process that significantly lowers contamination risk so as to merit an updated risk assessment study. Beyond the scope of this paper, but still entirely relevant to the fracking debate in general and to the consequences of an unconventional oil and gas industry in the State of North Carolina in particular, are other fracking-related social and economic issues which must not be overlooked by decision makers and should not be overlooked by individuals who desire a completely holistic understanding of the direct and indirect, positive and negative, effects of fracking.

Finally, consider that the market price of WTO crude oil is near \$50/barrel in April 2015, hitting a six-year low last month, and that a decrease in the price of oil also depresses the price of natural gas (because the two function economically as imperfect substitutes for processes that require liquid fuel as an input) (Egan 2015; Nasdaq 2015).

The current market conditions are highly unfavorable for and potentially economically prohibitive of developing North Carolina's unconventional oil and gas resources in the immediate and near future. The typical lifespan of wells in unconventional reservoirs is only 20-30 years, so if fracking comes to the state, it will be a temporary industry, with the bulk of production occurring in the first few decades. In North Carolina, there is no pressing need or even much upside to fracking now as opposed to later; the oil and gas deposits beneath the state's surface will always be available for extraction in the future once the global energy market shows signs of a more lucrative time for expanding production of domestic unconventional oil and gas.

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