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North Carolina Oil and Gas Study under Session Law 2011-276

March 2012

Prepared by the North Carolina Department of Environment and Natural Resources, the North Carolina Department of Commerce, the North Carolina Department of Justice and RAFI-USA

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Executive Summary

Background

In Session Law 2011-276, the North Carolina General Assembly directed the North Carolina Department of Environment and Natural Resources (DENR), the Department of Commerce (Commerce), and the Department of Justice, in conjunction with the nonprofit Rural Advancement Foundation International (RAFI), to study the issue of oil and gas exploration in the state and specifically the use of directional and horizontal drilling and hydraulic fracturing for natural gas production.

DENR researched oil and gas resources present in the Triassic Basins (Section 1 of this report), methods of exploration and extraction of oil and gas (Section 2), potential impacts on infrastructure, including roads, pipelines and water and wastewater services (Section 3), potential environmental and health impacts (Section 4), potential social impacts (Section 6), and potential oversight and administrative issues associated with an oil and gas regulatory program (Section 7).

S.L. 2011-276 directed the Department of Commerce, in consultation with DENR, to gather information on potential economic impacts of natural gas exploration and development (Section 5 of this report). Department of Commerce prepared Sections 5.A through 5.F of the report which discuss job creation and other projected economic impacts of natural gas drilling. DENR prepared Sections 5.G though 5.N which address the different financial tools (such as bonding requirements and severance taxes) used by oil and gas producing states to assure funding for reclamation of drilling sites, cover regulatory costs and offset public infrastructure costs.

The law directed the Consumer Protection Division of the Department of Justice to study consumer protection and legal issues relevant to oil and gas exploration in the state, including matters of contract and property law, mineral leases, and landowner rights (Section 8). The Consumer Protection Division was directed to consult with RAFI on the consumer protection issues.

Study Limitations

As requested by the General Assembly, this report analyzes the potential environmental, health, economic, social and consumer protection impacts that an oil and gas extraction industry may have in North Carolina. The analysis is constrained by the limited information available at this time. We do not have detailed or comprehensive information on the extent and richness of the shale gas resource in North Carolina. For purposes of this report we have been forced to extrapolate from data gathered from only two wells in the Sanford sub-basin; those well values have been averaged to project an estimate of the natural gas resource potentially available in that sub-basin. Since there are only two data points and the two wells have significantly different values, it is not clear how well the average value represents the resource throughout the Sanford sub-basin. This report generally uses the Sanford sub-basin as the basic unit for analysis of all impacts because the available data came from that sub-basin.

The Sanford sub-basin represents only a fraction of the total Triassic basin formations in the state – approximately 59,000 acres out of a total of 785,000 acres.

These limitations carry over into the assessment of both potential economic and environmental impacts. DENR projected the number of wells and total gas production *for the Sanford sub-basin,* using the limited data derived from averaging the values of two wells. Those projections are used throughout the report as the basis for assessing economic and environmental impacts.

Many impacts of natural gas extraction will vary based on local characteristics, such as water resources and even the weather. For example, the depth and quality of groundwater resources in the Triassic basins of North Carolina appear to be very different from conditions in the Marcellus shale formations in Pennsylvania. North Carolina does not seem to have as great a separation between potential drinking water resources and the gas-producing zone; understanding the geology and groundwater hydrology of North Carolina's shale formations will be critical to ensuring protection of drinkable groundwater. In terms of infrastructure impacts, weather can be an important factor. A local government official in Pennsylvania told DENR staff that when the natural gas industry first came to Pennsylvania from the South, oil and gas operators were surprised at how the harshness of the winters magnified the road damage caused by heavy oil and gas trucks.

There are some aspects of oil and natural gas extraction for which data is extremely limited even at a national level; the limited time available to prepare this report prevented us from taking into account additional research that is currently underway. This includes EPA's research on potential groundwater impacts in Pavillion, Wyo., and Dimock, Pa. and EPA's study of hydraulic fracturing and its potential impact on drinking water resources. EPA's first report of results related to drinking water is expected in 2012; the final report is not expected until 2014.

To our knowledge, no comprehensive studies are currently available on the long-term impacts to health from hydraulic fracturing for natural gas, and DENR is not qualified to conduct such a study. DENR recognizes that questions remain about health impacts. The EPA drinking water study may provide additional insight on heath effects. In March 2012, the New York State Assembly proposed $100,000 in its budget for an independent health impact study of hydraulic fracturing to be conducted by a school of public health following a model recommended by the Centers for Disease Control and Prevention.

Key Findings

North Carolina's potential shale gas resource

Most of the N.C. Geological Survey's information on potential shale gas resources in the state comes from the Sanford sub-basin of the Deep River geologic basin — a 150-mile-long area that runs from Granville County southwestward across Durham, Orange, Wake, Chatham, Lee, Moore, Montgomery, Richmond, Anson and Union counties into South Carolina.

The Deep River Basin is one of several similar geologic formations in North Carolina that cover approximately 785,000 acres.

The available organic geochemical and seismic data has caused NCGS to focus on an area of more than 59,000 acres in the Sanford sub-basin as the most promising location for organic-rich shale and coals from which natural gas can be extracted.

The shale formation in this area can be found at depths generally ranging between 2,100 and 6,000 feet below the surface. This particular shale formation has a maximum thickness of 800 feet and an average thickness that ranges from 180 to 540 feet.

Hydraulic Fracturing

Natural gas extraction by hydraulic fracturing involves drilling a well vertically and then horizontally into the shale formation. The natural gas production company perforates the well and then pumps fracturing fluid into the well under pressure to fracture the shale.

Fracturing fluids are composed primarily of water and a proppant (such as sand) to keep the fractures open. Water and sand represent between 98 percent and 99.5 percent of the fracturing fluid. The fluid also includes chemical additives used to condition the water. Additives may be used to thicken or thin the fluid, prevent corrosion of the well casing, kill bacteria or for other purposes.

The exact makeup of fracturing fluid varies from company to company and may also be adjusted based on conditions at the individual well site. Several hundred chemical compounds have been identified by the industry as chemicals that have been used in fracturing fluid. Any single fracturing fluid generally contains between 6 and 12 chemical additives.

Some chemicals that have been used in fracturing fluids, such as diesel fuel, have raised concern because of potential health impacts. EPA has discouraged use of diesel fuel in hydraulic fracturing.

Environmental Impacts

Water Supply: Hydraulic fracturing requires between 3 and 5 million gallons of water per well. To put this in perspective, a number of small cities in North Carolina withdraw 5 million gallons per day to serve their water system customers.

Based on some informed assumptions about the number of wells that could potentially be located in the Sanford sub-basin and the pace of well development, there appear to be adequate surface water supplies to meet the needs of the industry.

The timing of water withdrawals will need to be managed, however, to avoid injury to other water users and the environment. A 3 million gallon withdrawal made over a three-day period (which is technically possible for the industry) has a much greater potential impact than a 3 million gallon withdrawal made over the course of three weeks. In the absence of permit conditions to prevent rapid withdrawals during drought or seasonal low flow periods, streams can run dry and other water users may be harmed.

Water Quality: In the Sanford sub-basin, there appears to be much less separation between groundwater used for drinking water and the gas-producing layer than in other gas-producing states. Water supply wells of up to 1,000 feet deep have been found in North Carolina's Triassic Basins and the depth to which freshwater extends is unknown. Some of 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. (By contrast, the Pennsylvania shale gas resource lies at depths of roughly 10,000 feet or more and the deepest water supply wells are generally no more than 600 feet deep.)

At least two recent studies have found higher levels of methane in groundwater near natural gas wells that had been hydraulically fractured. In Pavillion, Wyo., EPA found methane of thermogenic origin and organic chemicals consistent with those used in hydraulic fracturing fluids in both monitoring wells and water supply wells. Conditions in Pavillion are not necessarily representative of most shale plays, however; the hydraulic fracturing that occurred in Pavillion involved injection of hydraulic fracturing fluids directly into the same formation tapped by water supply wells.

A study in Pennsylvania found methane water supply wells close to active exploration and production wells in the Marcellus shale have higher levels of dissolved methane than wells farther away. The study did not find constituents of hydraulic fracturing fluids in any of the water supply wells that were sampled. The study did find methane in water supply wells. The methane had an isotopic signature indicating that it originated from deep, thermogenic sources consistent with a Marcellus shale source, rather than from shallow biogenic sources. The lack of pre-drilling groundwater samples make it difficult to definitively link the methane to drilling practices.

Water quality problems have been associated with oil and gas operations generally; the problems can result from a number of production activities other than hydraulic fracturing. A Groundwater Protection Council study found that most Texas groundwater contamination incidents related to oil and gas activity reviewed were traced to either the production phase of well operations or involved waste management and disposal.

Oil and gas exploration and production can disturb large areas of land to develop access roads, well pads, impoundments and other infrastructure. These activities have impacts very similar to the stormwater impacts of any large development project: sedimentation and erosion, water pollution, increased peak discharges, increased frequency and severity of flooding, and other stormwater concerns. Unlike other construction projects, oil and gas exploration and production activities are exempt from federal Clean Water Act stormwater requirements.

Air Quality: Federal Clean Air Act standards have only been adopted for natural gas processing facilities. In 2011, EPA developed draft standards for air emissions from natural gas exploration and production activities. As proposed, the rules would affect gas wellheads, centrifugal compressors, reciprocating compressors, pneumatic controllers, storage vessels and sweetening units. Until the proposed rules go into effect, no federal new source performance standards or hazardous air pollution standards apply to emissions from these natural gas exploration and production activities. EPA had originally planned to finalize the rules by Feb. 28, 2012, but that timeline has been pushed back due to an extended public comment period.

A recent New York Environmental Impact Statement estimated that statewide NOx emissions could be increased by 3.7 percent from hydraulic fracturing operations and as much as 10.4 percent in the upstate New York area where the Marcellus Shale is located. These increases in

NOx emissions raise concerns for the impact on ozone concentrations and the state's ability to attain and maintain compliance with the federal ozone standard.

With the exception of internal combustion engine standards, North Carolina's state air toxics standards will be the only air quality rules that apply to many natural gas production activities, at least until EPA finalizes the proposed new source performance standards and hazardous air pollution rules for natural gas production.

Earthquakes: Hydraulic fracturing fluid under pressure cracks the surrounding rock; these cracks generate vibrations while breaking and can be picked up by sensitive geophones.

Data from other states suggests that the process of hydraulic fracturing causes microseismic events that do not pose a threat to the environment or human health or safety. An Oklahoma Geologic Survey study of an earthquake complaint near a hydraulic fracturing operation found that seismographs had recorded as many as 50 very small events on the day of the complaint. Most of the earthquakes occurred within a 24-hour period after the hydraulic fracturing operations had ceased and were so minor (between 1 and 2.4 on the Richter scale) that they could not be felt.

Most reports of significantly increased earthquake activity have occurred in regions where disposal wells are operated and related to underground injection of waste rather than hydraulic fracturing. Only a small fraction of injection wells have caused significant seismic activity. Limiting injection volumes, decreasing pressure and distributing the waste between more disposal wells have been shown to reduce and even eliminate induced seismicity, while reusing and recycling of wastewater can reduce the need for other waste management options.

Wastewater and Solid Waste: Between 9 and 35 percent of the fluid pumped into a well for hydraulic fracturing returns to the surface as "flowback" shortly after fracturing. During the remainder of the productive life of the well, a much smaller volume of wastewater is generated more or less continuously as the well produces gas; this wastewater is produced water.

In many states, flowback or produced water from a drilling operation can be disposed of by underground injection. N.C. General Statute 143-214.2(b) prohibits the use of wells for waste disposal.

It is not clear that injection wells would be a feasible option for managing produced waters from a gas well in the Triassic Basins of North Carolina. The areas with potential for natural gas development have not been sufficiently characterized to determine whether the formations would be suitable for disposal of shale gas production wastewater. The sedimentary rocks of these basins generally have very low permeability, and natural fractures are responsible for nearly all of the permeability and groundwater movement in these basins. Disposal by injection into fractured rock presents difficulty in predicting the fate and transport of the injected wastewaters. These conditions suggest that Triassic Basins in North Carolina generally do not have suitable hydrogeologic conditions for disposal by injection.

Some wastewater streams can go to a municipal wastewater treatment plant. These waste streams can be difficult to treat in a conventional wastewater treatment plant, however, and it would be advisable to require pretreatment.

A number of states allow land-application of produced water from hydraulic fracturing. The acceptability of wastewater for that purpose may depend on its quality at the time of land application since high levels of salts and chlorides can be a problem.

Chesapeake Energy is currently recycling and reusing 100 percent of the flowback water that returns to the surface (only a small percentage of the volume of water used in hydraulic fracturing) by a filtering process.

EPA has exempted “drilling fluids, produced waters, and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy” from regulation under the Resource Conservation and Recovery Act (RCRA) -- the federal statute that regulates hazardous waste.

Since some exploration and production wastes may have the characteristics of hazardous wastes, but are not regulated under RCRA, oil and gas-producing states have generally developed specific standards for handling exploration and production wastes. North Carolina does not have standards that specifically address disposal of or transportation of exploration and production waste.

Since North Carolina statutes and rules have not been written to address these particular types of wastes, existing state rules would allow disposal of all RCRA-exempt exploration and production wastes (other than oils and liquid hydrocarbons) in a municipal solid waste (MSW) landfill. Although North Carolina has strong standards for design and construction of both industrial and MSW landfills, those standards were not developed for disposal of hazardous waste.

Economic Analysis

The economic impact analysis focuses on the statewide economic impact of gas drilling activities in the Sanford sub-basin. (The Sanford sub-basin is approximately 59,000 acres of the 785,000 acres of the Triassic Basins in North Carolina.) The analysis does not take site preparation, leasing of land, hydraulic fracturing or extraction, production or transmission of gas into consideration.

Review of studies from other parts of the country show that a large infusion of economic activity from shale gas drilling will increase the incomes of some individuals and communities and will add jobs. Without reliable expenditure inputs for North Carolina, however, it remains uncertain how much wealth, income or benefits from long-term employment would accrue to Lee, Chatham and surrounding counties.

For its analysis, the Department of Commerce used the IMPLAN model. IMPLAN allows researchers to develop local level input-output models to estimate the economic impacts associated with marginal changes in the economy, such as “shocks” of new production or output.

The model estimates that North Carolina vendors will provide only 36 percent of drilling investments. Since North Carolina does not presently have a developed fossil fuel extraction industry, there will likely be substantial economic “leakages” as dollars are spent outside the

North Carolina economy. For example, drilling requires specialized equipment that is not available from in-state companies.

The IMPLAN model estimates drilling activities in the Sanford sub-basin would sustain an average of 387 jobs per annum over the seven-year time period studied:

- In the peak well year, drilling activities are estimated to sustain 858 jobs over a one-year period.
- In Year 1, the year with the lowest level of drilling expenditures, the IMPLAN model estimates that 59 jobs will be either created or partially supported by these expenditures.

At the completion of all drilling activities in the state, it is estimated the economy will have increased output by $453 million. Output represents the level of all economic activity from production and is typically larger than value added impacts, which measure the direct change in North Carolina's gross domestic product (GDP). Anticipated drilling activities are estimated to positively affect the state's GDP by $292 million by year 2019.

It is not likely that North Carolina's shale play will be developed in the near-term. IHS Global Insight, in a December 2011 study for the American Natural Gas Alliance, reported that six prominent plays are expected to account for more than 90 percent of U.S. shale capacity by 2035. North Carolina was not on this list and, at this time, does not appear on U.S. Geological Survey maps of North American shale plays.

Low natural gas prices also make activity in North Carolina unlikely in the near-term. The Energy Information Administration's preliminary 2012 *Annual Energy Outlook* assumes that with increased production, average annual wellhead prices for natural gas will remain below $5 per thousand cubic feet (2010 dollars) through 2023. Low prices make it less likely that the industry will move from areas already in production to a new and unproven area.

Bonding: North Carolina Session Law 2011-276 revised the amount of the bond required for an oil and gas-drilling permit to $5,000 plus $1 per linear foot. Under North Carolina's law, the bond only covers proper closure and abandonment of the well. The bond does not cover the costs of restoring the surface of the site to pre-existing conditions or remediation of any contamination caused by the drilling operation.

States vary significantly in the amount of bond required per well, but typically the uses of those bonds extend beyond well closure and often cover site reclamation.

As one measure of the adequacy of bond requirements for wells on public lands, the General Accounting Office (GAO) looked at the cost to the Bureau of Land Management of reclaiming orphan wells. Over a 21-year period, BLM spent about $3.8 million to reclaim 295 orphaned wells, or an average of about $12,900 per well. The GAO report states that "the amount spent per reclamation project varied greatly, from a high of $582,829 for a single well in Wyoming in fiscal year 2008 to a low of $300 for 3 wells in Wyoming in fiscal year 1994." The BLM also estimated the costs of wells it has yet to reclaim at approximately $1.7 million for 102 orphaned wells, an average of roughly $16,700 per well.

Severance Taxes: North Carolina's Oil and Gas Conservation Act currently sets the state's severance tax for natural gas at 5/100 of a cent – $.0005 per 1,000 cubic feet of gas. The revenues can only be used to pay the costs of administering the law.

North Carolina has one of the lowest severance taxes in the nation. With the exception of those states that do not assess any severance tax, North Carolina's tax rate was the lowest of all states for which severance taxes were identified as part of this study. Maryland, New York and Pennsylvania do not assess severance taxes on the production of natural gas, however, Pennsylvania recently enacted a law imposing an "impact fee" on natural gas production, and New York assesses a "property type production tax" on the amount of natural gas produced.

Community, Infrastructure and Social Impacts

In Pennsylvania, road impacts have been a major problem for municipalities in the Marcellus shale region. Gas development significantly increases truck traffic on roads that often were not designed for such heavy use. For many of Pennsylvania's small towns, road maintenance and repair accounts for the largest part of the town budget.

New York's EIS estimated 1,148 one-way heavy-duty truck trips and 831 one-way light-duty truck trips per well during the construction phase of gas development. For early well pad development, this is a total of 2,296 round-trip heavy-duty truck trips and 1,662 round-trip light-duty truck trips per well when all water is transported by truck.

In some states, natural gas production companies have entered into road maintenance agreements with local government – committing to return the roads to good condition.

Pennsylvania recently enacted a local option impact assessment to provide additional revenue to counties and towns affected by drilling activity.

Significant increases in truck traffic can lead to an increase in accidents and increased demand for traffic control. Both place additional demand on police and other emergency services. Given the volume and nature of the liquids being transported, accident response can be both more complex and more time-consuming than a typical one- or two-car accident.

Spills of hazardous chemicals require labor- and time-intensive responses from law enforcement and environmental agencies. In regions unaccustomed to oil and gas activity, the specialized nature of the response required for spills, explosions or fires related to the industry might necessitate new equipment, training and staff. This can place a special strain on rural areas still served by volunteer fire and rescue services.

As drilling activity has increased in certain parts of the United States, rural areas and small towns have, in some cases, been overwhelmed by the demand for worker housing. The impact of gas production on housing costs and availability likely depends on three key factors: 1) the speed and scale of industry growth in a given community; 2) the existing housing capacity of a community before drilling begins; and 3) the industry's need to import workers skilled in gas production activities.

Property owners who control the mineral rights to economically recoverable gas resources under their land may see substantial increases in property values. Analysis claimed that the taxable value of oil and gas properties in Texas' Barnett shale region increased from $341 million to $5.9 billion, a 1,730 percent increase, from 2000-2005. Other studies of property values have generally shown much more modest increases.

Increased value can be attributed to two financial benefits to property owners: bonuses upon signing an oil and gas lease agreement and royalty payments. Lease agreements can range anywhere from $5 per acre to $20,000 per acre. On properties where lease agreements have not been signed, potential buyers may factor an expected bonus payment into the value of the property. Mineral owners receive royalties on income from gas production, typically earning 12.5 percent to 20 percent of the gas revenue generated at their wellhead.

Regulatory Program

The fact that oil and gas production activities are exempt from a number of federal environmental statutes that otherwise apply to industrial activities places a special burden on oil and gas-producing states to create adequate state regulatory programs.

Storage and disposal of oil and gas wastes have been exempted from federal hazardous waste regulation, specifically to allow states to develop tailored programs for management of those wastes. Congress has also deferred to the states to regulate stormwater runoff from drilling sites, exempting those sites from Clean Water Act permitting requirements for construction stormwater and industrial stormwater discharges.

States that have a long history of oil and gas production typically have very detailed regulations for well siting, well construction, wastewater disposal, storage and disposal of solid wastes, and water use. Since North Carolina does not have an active oil and gas industry, the state does not have standards appropriate for the special nature of these activities and the waste products generated in the process.

Guidelines for state oil and gas regulatory programs developed by the State Review of Oil and Natural Gas Environmental Regulations (STRONGER) recommend:

- Standards for casing and cementing sufficient to handle highly pressurized injection of fluids into a well for purposes of fracturing bedrock and extracting gas.
- Rules requiring the driller to identify potential conduits for fluid migration; address management of the extent of fracturing; and identify actions to be taken in response to operational or mechanical problems.
- Standards for dikes, pits and tanks, including contingency planning and spill risk management procedures.
- Waste characterization, including testing of fracturing fluids. Waste should be tracked to ensure appropriate disposal.
- Prior notification of fracturing activity.
- Assessment of water use for hydraulic fracturing in terms of volume in light of water supply, competing water uses and the environmental impacts of withdrawing water for

fracturing. Use of alternative water sources and recycling of water should be encouraged.

Recommendations for siting standards, such as setbacks from streams, wetlands and floodplains, can be found in the New York Department of Environmental Control EIS and in recent legislation enacted in Pennsylvania.

In the last three years, a number of states have moved to require disclosure of the chemicals used in hydraulic fracturing fluids to state regulatory and emergency response agencies. Several states have also required disclosure to the public with appropriate safeguards for proprietary information.

Oil and gas producing states have also found it necessary to address the issue of local authority to regulate natural gas production activities. Several states that have comprehensive state oil and gas regulatory programs continue to allow local governments to exercise some degree of planning and zoning authority with respect to production activities.

Conclusions and Recommendations

After reviewing other studies and experiences in oil and gas-producing states, DENR believes that hydraulic fracturing can be done safely as long as the right protections are in place. It will be important to have those measures in place before issuing permits for hydraulic fracturing in North Carolina's shale formations. A number of states have experienced problems associated with natural gas exploration and development because the appropriate measures were not in place from the beginning – forcing both the state and the industry to react after damage had already been done. DENR has identified a number of immediate recommendations for management of natural gas exploration and development activities. A complete oil and gas permitting program will require more detailed standards than it is possible to provide in this report and those standards should be based on conditions in North Carolina. Conditions in the Triassic Basins of North Carolina are not identical to those found in Pennsylvania or other gas-producing states. For example, a better understanding of the depth of usable groundwater in the Triassic Basin will be necessary to set well construction standards that will adequately protect drinking water resources.

Based on the research and analysis in this report, the Department of Environment and Natural Resources in consultation with the Department of Commerce developed the following recommendations for the General Assembly. It should be noted that these recommendations do not take into account information from the Department of Justice's section on consumer protection, because DENR had not received that section of the report in time for preparation of the recommendations. These recommendations also do not take into account public comments, which will be collected in before the report is finalized.

A brief description of each recommendation is listed; a more detailed explanation of each recommendation is included in Section 9. The recommendations are not listed in order of priority.

1. **Collect baseline data including groundwater, surface water and air.**

2. **Require oil and gas operators to prepare and have a DENR-approved Water Management Plan and limit water withdrawals to 20 percent of the 7Q10 stream flow.**
3. **Enhance existing oil and gas well construction standards to address the additional pressures of horizontal drilling and hydraulic fracturing.**
4. **Develop setback requirements and identify areas (such as floodplains) where oil and gas exploration and production activities should be prohibited.**
5. **Develop a state stormwater regulatory program for oil and gas drilling sites.**
6. **Develop specific standards for management of oil and gas wastes.**
7. **Require full disclosure of hydraulic fracturing chemicals and constituents to regulatory agencies. With the exception of trade secrets, require public disclosure of hydraulic fracturing chemicals and constituents.**
8. **Prohibit the use of diesel fuel in hydraulic fracturing fluids.**
9. **Improve data management capabilities and develop an e-permitting program.**
10. **Ensure that state agencies, local first responders and industry are prepared to respond to a well blowout, chemical spill or other emergency.**
11. **Develop a modern oil and gas regulatory program, taking into consideration the processes involved in hydraulic fracturing and horizontal drilling technologies, and long-term prevention of physical or economic waste in developing oil and gas resources.**
12. **Keep the environmental permitting program for oil and gas activities in DENR where it will benefit from the expertise of state geological staff and the ability to coordinate air, land and water quality permitting.**
13. **Develop a coordinated permitting process.**
14. **Address the distribution of revenues from oil and gas excise taxes and fees to support the oil and gas regulatory program, fund environmental initiatives and support local governments impacted by the industry.**
15. **Identify a source of funding for repair of roads damaged by truck traffic and heavy equipment.**
16. **Clarify the extent of local government regulatory authority over oil and gas exploration and production activities.**
17. **Complete additional research on impacts to local governments and local infrastructure.**
18. **Complete additional research on potential economic impacts.**
19. **Address the natural gas industry's liability for environmental contamination caused by exploration and development, particularly for groundwater contamination.**
20. **Provide additional public participation opportunities**

Recommendations on issues related to property rights and consumer protection will be added when Section 8 of the report has been completed.

Introduction

The North Carolina Geological Survey (NCGS) has identified a potentially valuable natural gas resource in the Triassic Basins of North Carolina. Preliminary results show that at least 59,000 acres in the Sanford sub-basin of the Deep River Basin contain organic-rich shale and coals from which natural gas can be captured. The NCGS continues to collect and analyze data on the potential for natural gas resources in the Triassic Basins, including the Dan River Basin and the other areas of the Deep River Basin. At the same time, the U.S. Geological Survey is working on an assessment of natural gas resources for all Mesozoic basins along the East Coast, which includes the Triassic Basins of North Carolina. Results from the USGS assessment will not be available until the summer of 2012.

In 2011, interest in the potential natural gas resource in North Carolina prompted the North Carolina General Assembly to direct the North Carolina Department of Environment and Natural Resources (DENR), the Department of Commerce (Commerce), and the Department of Justice, in conjunction with the nonprofit Rural Advancement Foundation International (RAFI), to study the issue of oil and gas exploration in the state and specifically the use of directional and horizontal drilling and hydraulic fracturing for that purpose.

Session Law 2011-276 directs DENR to address a number of issues related to the exploration and production of oil and gas. S.L. 2011-276 also assigns certain sections of the report to other departments and organizations. DENR was assigned to report on oil and gas resources present in the Triassic Basins (Section 1 of this report), methods of exploration and extraction of oil and gas (Section 2), potential impacts on infrastructure, including roads, pipelines and water and wastewater services (Section 3), potential environmental and health impacts (Section 4), potential social impacts (Section 6), and potential oversight and administrative issues associated with an oil and gas regulatory program (Section 7).

The law directs the Department of Commerce, in consultation with the Department of Environment and Natural Resources, to gather information on potential economic impacts of natural gas exploration and development (Section 5 of this report). Commerce prepared Sections 5.A through 5.F of this report which discusses job creation and other projected economic impacts of natural gas drilling. DENR prepared Sections 5.G though 5.N which address the different financial tools (such as bonding requirements and severance taxes) used by oil and gas producing states to assure funding for reclamation of drilling sites, cover regulatory costs, and offset public infrastructure costs.

The law directs the Consumer Protection Division of the Department of Justice to study consumer protection and legal issues relevant to oil and gas exploration in the state, including matters of contract and property law, mineral leases, and landowner rights (Section 8). The Consumer Protection Division is directed to consult with RAFI on this section.

Recommendations and limitations are discussed in Section 9 of this report.

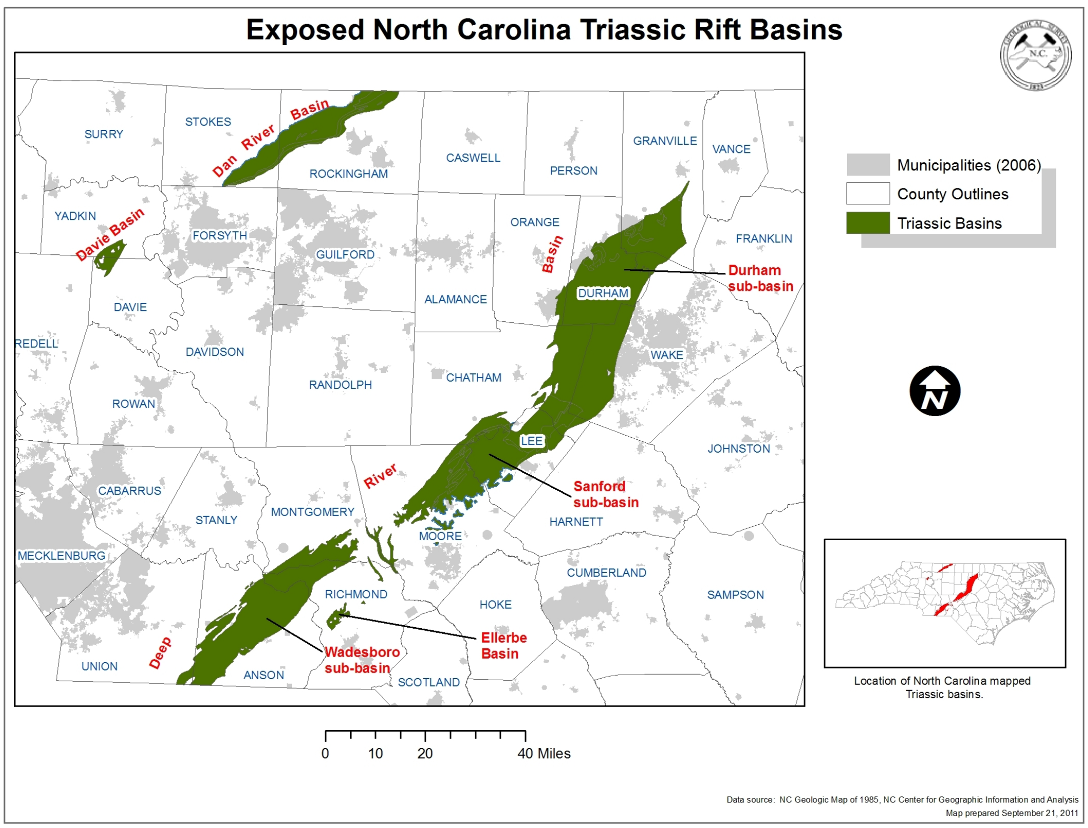
Section 1 – Potential Oil and Gas Resources

A. Overview of the Triassic Basins

The geologic term "basin" refers to a low area in the earth's crust, formed by the warping of the crust from mountain-building forces, in which sediments have accumulated. The Triassic Basins in North Carolina are elongated basins bounded by faults along their long sides. These basins formed 235 to 200 million years ago, during the Triassic Period, when Africa and North America were beginning to split apart to form the Atlantic Ocean. This type of basin is called a rift valley.

Four Triassic Basins are exposed and outcrop at the earth's surface in North Carolina: Deep River, Dan River, Davie and the Ellerbe (see Figure 1-1). The Dan River Basin is the North Carolina portion of continuous rift basin that extends from Stokes County northwest across Rockingham County and into Virginia. In Virginia, the basin is called the Danville.

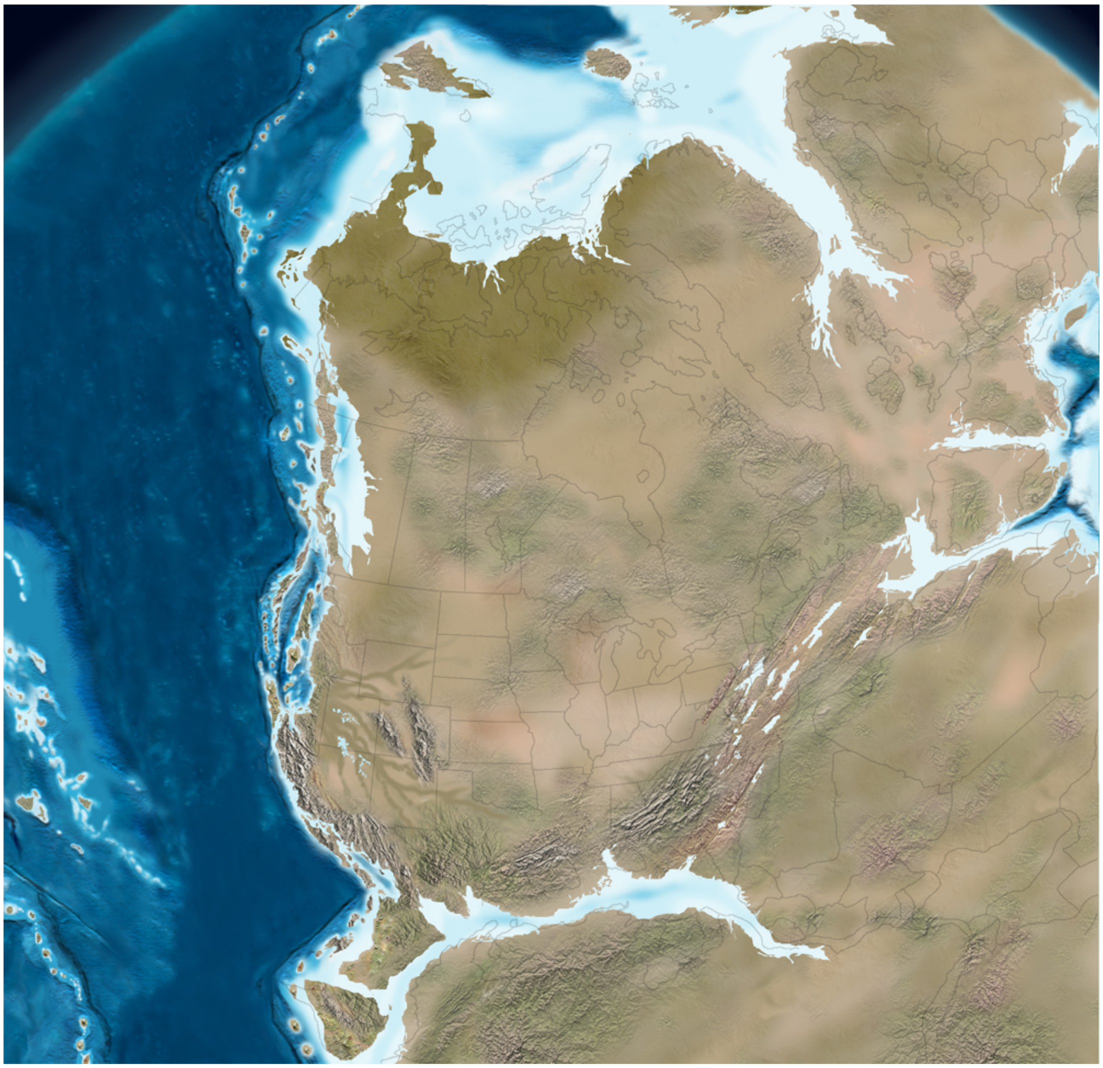
Figure 1-1. Exposed North Carolina Triassic Basins



The Deep River is a 150-mile-long rift basin that runs from Granville County southwestward across Durham, Orange, Wake, Chatham, Lee, Moore, Montgomery, Richmond, Anson and Union counties into South Carolina. The basin is subdivided into three sub-basins: Durham, Sanford and Wadesboro. The Ellerbe Basin in Richmond County has been interpreted as an erosional remnant of the larger Deep River Basin. The areas of these basins are: Davie – 20.04 square miles, Dan River – 152.02 square miles and Deep River – 1,211.07 square miles.

The rift basins began to form approximately 210 million years ago with the breakup of the supercontinent Pangea (a large land mass that divided to become Africa and North America), which preceded the later opening of the Atlantic Ocean. Dr. Ron Blakey of Northern Arizona University is a paleogeographer who has reconstructed the shape of the continental landmasses over time. Figure 1-2 shows the Triassic paleogeography at the time when rifting had formed a series of freshwater lakes. At that time, North Carolina was located near the equator and sediment accumulated within the basins.

Figure 1-2. Triassic paleogeography approximately 210 million years ago, from Ron Blakey, NAU Geology. North Carolina can be identified from the current state outlines shown on the continent.



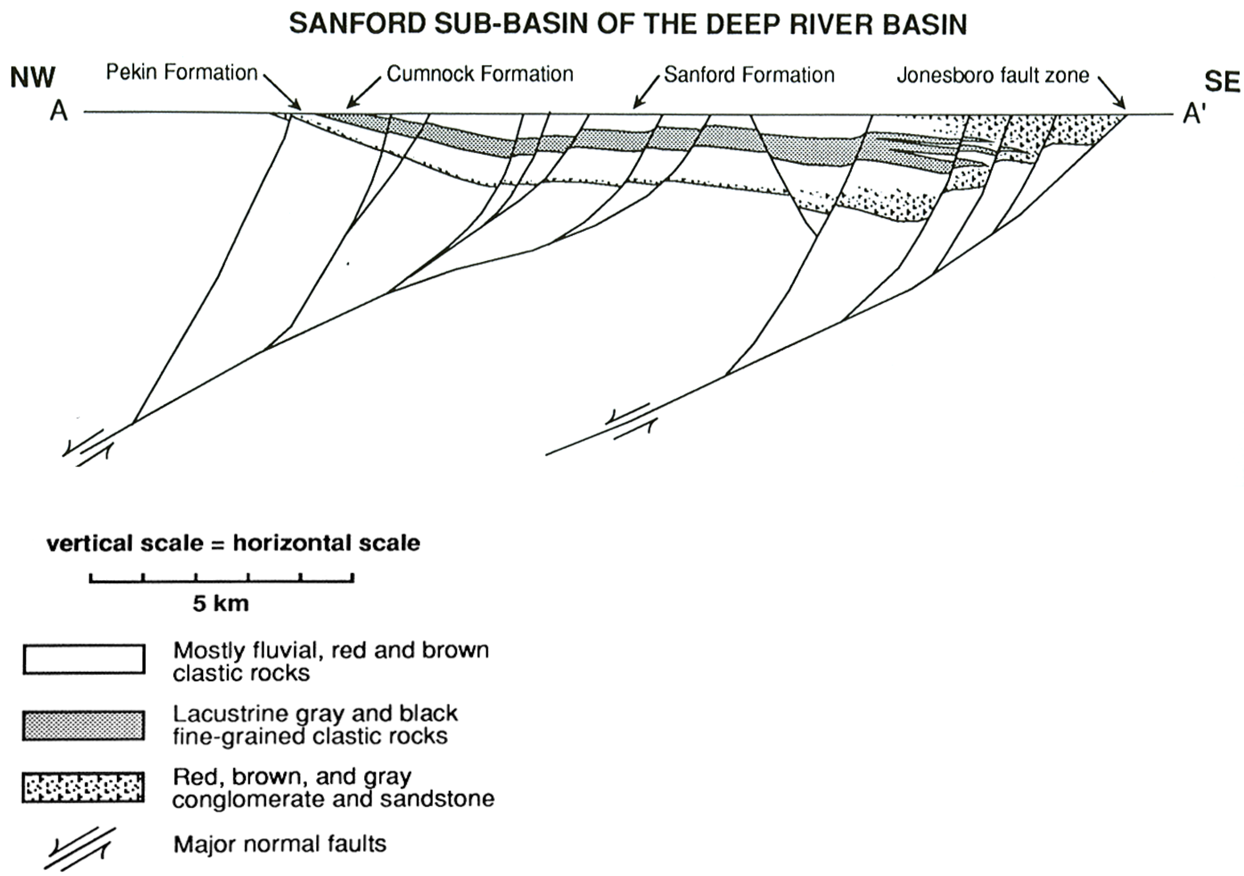
The Deep River Basin has a steeply dipping eastern border fault. Approximately 7,000 feet of Triassic strata has been deposited in this basin. The organic shale part of this basin is interpreted by geologists as shallow lake deposits that are similar to the African Rift Valley lakes, which are forming as the African tectonic plate is splitting apart today.

The Piedmont physiographic province included all Triassic or Mesozoic rift basins along the east coast of the United States: Hartford-Deerfield (Mass., Conn.), Newark (N.Y., N.J., Pa.), Gettysburg (Pa., Md.), Culpeper (Md., Va.), Taylorsville (Md., Va.), Richmond (Va.), Dan River-Danville (Va., N.C.), and Deep River (N.C., S.C.). Figure 1-3 illustrates the extent of the Mesozoic basins. During the Mesozoic era, North Carolina was near the equator.

Figure 1-3. The Mesozoic Basins of the eastern United States. The city of Raleigh is shown for reference and the Sanford sub-basin in outline by a red box.

To better understand the geology within the basin, we can look at a cross-section or vertical slice through the earth from the northwest to the southeast across the Sanford sub-basin of the Deep River Basin (Figure 1-4). What this section shows is an up to 800-foot thick organic-rich sedimentary rock (or shale) called the Cumnock Formation. The Cumnock Formation is sandwiched between the Sanford Formation sandstones above and the Pekin Formation sandstones below. The Cumnock Formation extends more than eight miles across the sub-basin.

Figure 1-4. Cross-section from northwest to southeast across the Sanford sub-basin.



As early as the Revolutionary War period, the Deep River Basin was known to produce coal. Underground coal mining occurred in the 1920s to 1940s. A 1925 mine explosion in Farmville, N.C., which killed 53 miners, was blamed in part on excess coal gas.

In 1974, a division of Chevron drilled the first oil exploration well (V.R. Gross LE-OT-1-74) in Lee County. In 1981, North American Exploration Inc. drilled six coal exploration holes in Moore (4) and Chatham (2) counties, and in 1982, Richard Beutel and Associates drilled the first coal-bed methane exploration well (Dummit-Palmer LE-OT-1-82). In 1983, Seaboard Exploration and Production Company drilled two more wells (Butler #1 LE-OT-1-83 and Bobby Hall #1 LE-OT-2-83).

In 1985 and 1986, seismic reflection lines that crisscrossed the sub-basin were collected to provide better target selection for future drilling. The location for the seismic lines, especially the down dip section (Line 113) was configured to pass as close as possible to the locations of prior unsuccessful wells (Dummit-Palmer, V.R. Gross and Bobby Hall #1). The seismic data had not been fully processed in 1987 when Sanford Exploration drilled the Elizabeth Gregson #1 (LE-OT-1-87) well; that well missed the entire organic shale formation.

Four years passed before Equitable Resources Exploration drilled Butler #2 (LE-OT-1-91) in 1991, along the Seismic Line 113. Again the results from the well gave indications of modest oil and/or gas shows, but not a potential conventional oil or gas resource.

In 1998, Amvest drilled two wells, one located along Seismic Line 113 (Simpson #1 LE-OT-1-98) and the other several miles off the line (Butler #3). Both wells were perforated and Amvest attempted to hydraulically fracture the wells using nitrogen foam. That fracturing effort was unsuccessful in both wells, but the wells flowed gas and Amvest placed a wellhead containing several pressure shut-off valves (also known as a Christmas tree) on each completed well. Eleven years later in March 2009, the two wells were sampled for natural gas and pressure tested. The pressure at the Simpson #1 well was 250 pounds per square inch (psi) and the pressure at Butler #3 was 900 psi.

B. Organic geochemical data

In 2008, Jeffrey Reid and Robert Milici published the organic geochemical data for the Deep River in the United States Geological Survey (USGS) Open File Report 2008-1108.[1] This report marked the first recognition by the North Carolina Geological Survey (NCGS) of this thick section of organic shale as a potential gas resource. The next year, the NCGS published "Information Circular 36: Natural Gas and Oil in North Carolina."[2] That same year, the NCGS issued Open-File Report 2009-01[3] and gas samples were taken from both shut-in wells, Simpson #1 and Butler #3. NCGS made a series of presentations and briefings to interested industry, governmental and environmental groups in 2009 and 2010.

For the successful commercial production of oil and gas, geologists look at three indicators in the shale: total organic carbon (TOC), kerogen type and thermal maturity. TOC is indicative of the quantity of organic matter available for the formation of hydrocarbons.

Kerogen type is an indication of the type of organic matter. When organic matter is buried in a basin, it is exposed to increasingly higher subsurface temperatures. When heated to temperatures of approximately 60°C or higher, kerogen yields bitumen – the fraction of organic matter that is soluble in organic solvents. Further heating then creates liquid hydrocarbons and hydrocarbon gas. Oil is produced within a certain temperature range, called the "oil window." As temperatures increase beyond the oil window, the hydrocarbons are cracked into natural

[1]Reid, Jeffrey C. and Robert C. Milici. "Hydrocarbon Source Rocks in the Deep River and Dan River Triassic Basins, North Carolina." U.S. Geological Survey Open-File Report 2008-1108.
[2]North Carolina Geological Survey. "Information Circular 36: Natural Gas and Oil in North Carolina." http://www.geology.enr.state.nc.us/pubs/PDF/NCGS_IC_36_Oil_and_Gas.pdf
[3]Reid, Jeffrey C. and Kenneth B. Taylor. "Shale Gas Potential in Triassic Strata of the Deep River Basin, Lee and Chatham Counties, North Carolina with pipeline and infrastructure data." North Carolina Geological Survey Open-file Report 2009-01.

gas. Type I kerogen indicates lake deposits with oil prone rocks. Type II indicates marine deposits with oil prone rocks. Type III indicates gas prone source rocks.[4]

Thermal maturity dictates the wetness of the gas. Natural gas that contains less methane and more ethane and other complex hydrocarbons is called wet gas. Natural gas that occurs without these liquid hydrocarbons is called dry gas. Table 1-1 below shows the stages of thermal maturity.

Table 1-1. Stages of Thermal Maturity[5]

Stage of Thermal Maturity	Temperature	Process	Product
Immature	<60°C	Bacterial and plant organic matter converted to kerogens and bitumen	Methane generated by microbial activity
Mature	60°C - 160°C	Rock generates and expels most of its oil	Oil
Postmature	>160°C	Postmature for oil/mature for gas	Condensate / wet gas and at higher temperatures, dry gas only

Thermal maturity of sedimentary rocks is evaluated based on vitrinite reflectance values (%Ro), thermal alteration and a parameter called T max. Vitrinite reflectance is a measure of the amount of light reflected by vitrinite (an organic component of kerogens) when examined under a microscope. Vitrinite reflectance is used as a measure of thermal maturity because it is sensitive to temperature ranges in a way that corresponds to hydrocarbon generation. It is measured by immersing grains of vitrinite in oil, and it is expressed as percent reflectance in oil, Ro. Table 1-2 shows thermal maturity based on vitrinite reflectance values.

Table 1-2. Interpreted Maturation Based on Vitrinite Reflectance Values[6]

Vitrinite Reflectance (%Ro)	Thermal Maturity
<0.60	Immature
0.60 – 1.00	Oil window
1.00 – 1.40	Condensate / wet gas window
>1.40	Dry gas window

[4]Jarvie, Dan. "Evaluation of Hydrocarbon Generation and Storage in the Barnet Shale, Ft. Worth Basin, Texas." Humble Instruments & Services, Inc. 2004. Accessed February 19, 2012. http://blumtexas.tripod.com/sitebuildercontent/sitebuilderfiles/humblebarnettshalepresptc.pdf

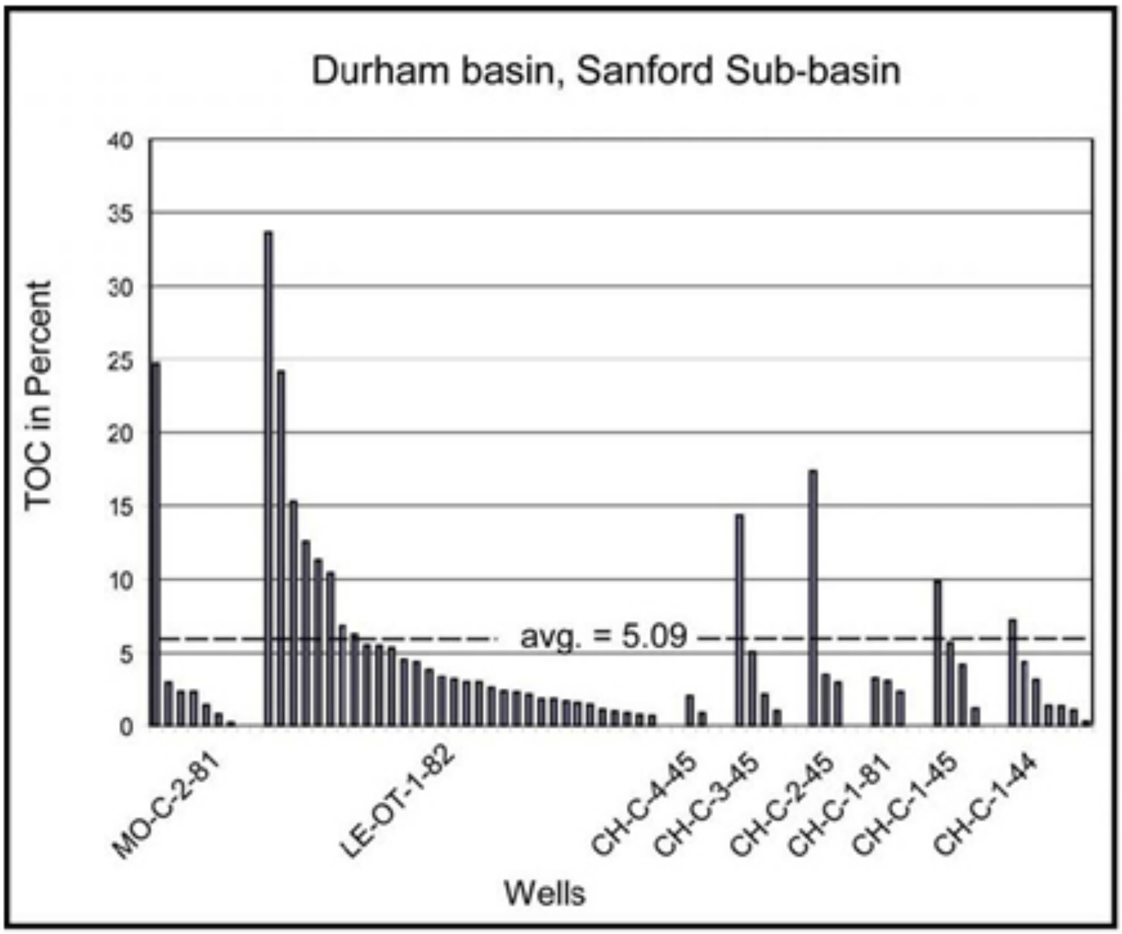
[5]Pennsylvania Department of Conservation and Natural Resources. "Thermal Maturation and Petroleum Generation." Accessed February 19, 2012. http://www.dcnr.state.pa.us/topogeo/oilandgas/sourcerock_maturation.aspx.

[6]Jarvie, 2004.

Tmax is the temperature at which the maximum release of hydrocarbons from cracking of kerogen occurs during organic decomposition. Tmax indicates the stage of maturation of the organic matter.

Analysis of the organic-rich lake sediments in the Triassic Basin showed that they are predominantly gas-prone with some oil shows. The TOC data exceeds the conservative 1.4 percent threshold necessary for hydrocarbon expulsion (Figure 1-5). The average TOC for the samples tested from the eight wells is 5.06 percent, 3.6 times the 1.4 percent threshold.[7]

Figure 1-5.Total Organic Carbon (TOC) as a percentage for samples from eight wells (seven coal holes and one oil test hole).



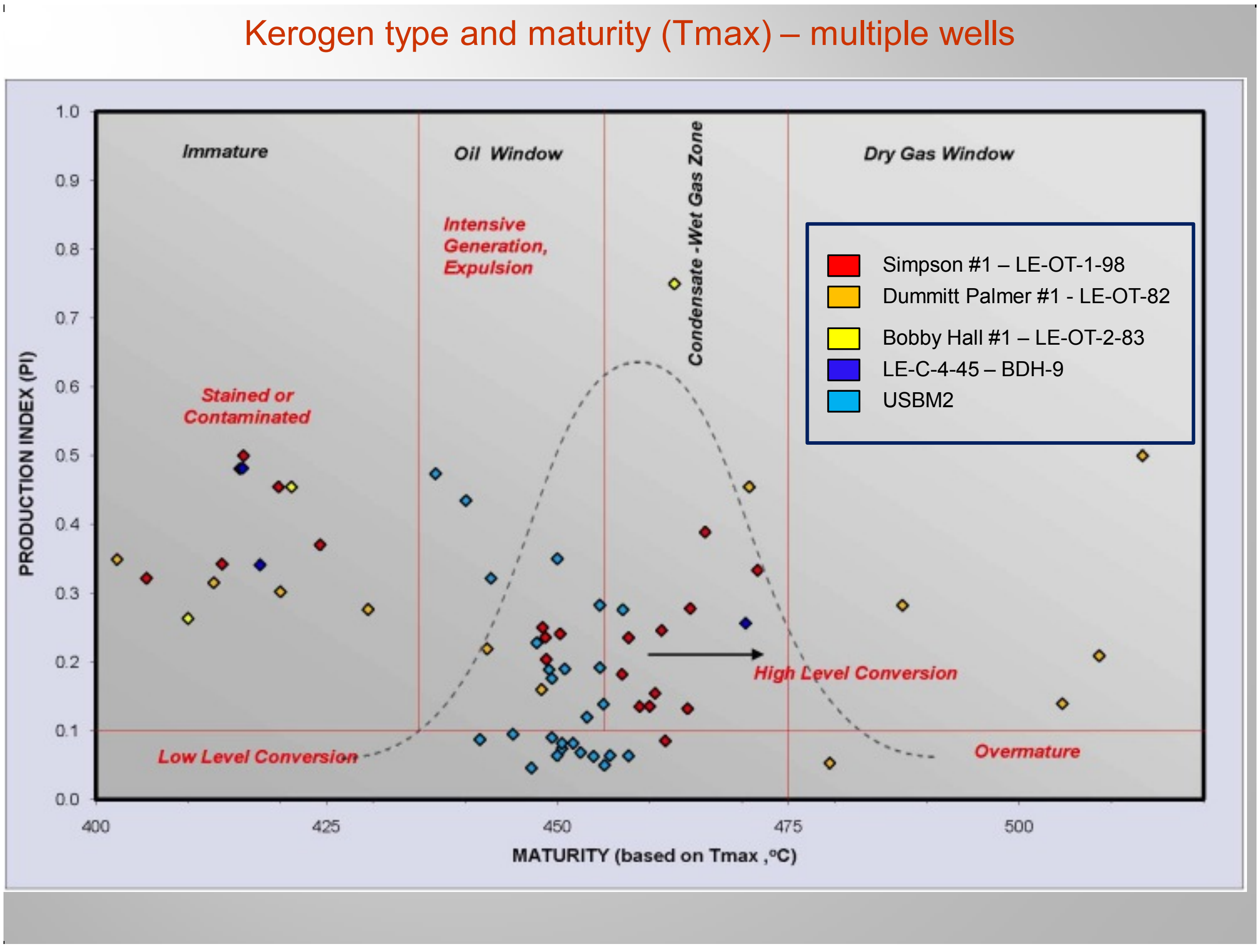
Geochemical laboratory tests also showed the organic matter is derived from terrestrial Type III woody (coaly) material and from lacustrine Type I (algal material), which is a preliminary indicator for wet gas (natural gas with light oil condensates). The quantity of potential gas volumes or the potential gas condensates is unknown from the geochemical test.

The thermal alteration index (TAI) data, which is used to determine the temperature rock has attained during its history, combined with the vitrinite reflectance data for the sediments in the

[7] Reid and Milici, 2008.

Triassic Basin, indicate levels of thermal maturity suitable to generate hydrocarbons. The maturity for a composite of data from five wells is shown in Figure 1-6. Samples from the Dummit-Palmer well range from immature to overmature. This well was located near a diabase dike – an intrusion of molten magma into the sedimentary basin shortly after the basin formed. The diabase heated the organic-rich shale and caused the hydrocarbons to be "overcooked;" as a result, these shales would not be suitable for the commercial production of oil or gas. For samples from the U.S. Bureau of Mines coal exploration hole #2, the data are clustering in the oil window to the condensate-wet gas zone. For data from the Simpson #1 well, more samples are in the condensate-wet gas zone.

Figure 1-6. Maturity (Tmax) for multiple wells. These data are color-coded to the five wells.

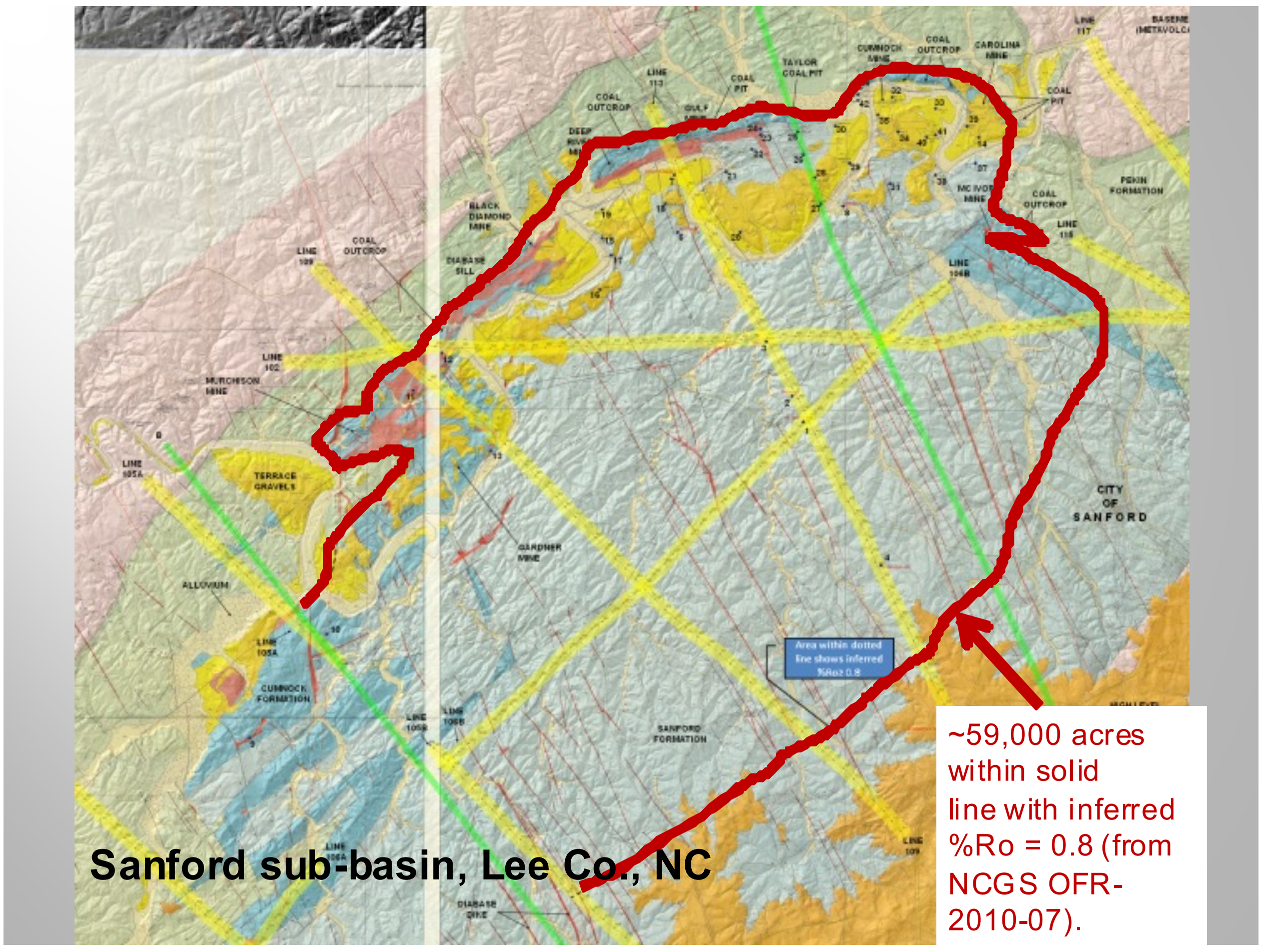


Combining the organic geochemical data with the interpretation of the 1985-86 seismic data delineated a potential target location with an area of more than 59,000 acres, which is shown in Figure 1-7. This compilation map shows the location of seismic lines, detailed geologic mapping from Reinemund (1947, 1955), the location of the coal mines, coal exploration holes, oil and gas test wells and the two interpreted geologic cross-sections by Reinemund.

The hill shade relief topography that forms the bottom layer of this figure is derived from LiDAR (Light Detection and Ranging), a remote sensing technology that illuminates targets with light.

The LiDAR was collected by the N.C. Floodplain Mapping Program in 2002. Several igneous intrusive (diabase dikes) are shown in red on the geologic map. The elevation tends to follow the diabase dikes, since these rocks weather quickly, but the ridges along their length are due to the baking of the country rock.

Figure 1-7. Map of part of the Sanford sub-basin showing the seismic lines (yellow), the coal mine locations, coal exploration holes and oil and gas test wells. The red line shows the approximately 59,000 acres where the vitrinite reflectance (%Ro) is greater than or equal to 0.8. The underlying geologic map is from Reinemund (1955) and the hill shade elevation is from LiDAR (N.C. Floodplain Mapping, 2002). The two green lines that run from the northwest to southeast on the map are the locations of two geologic cross-sections A – A' and B – B' constructed by Reinemund (1955).



To better understand the geometry and structure of the Sanford sub-basin, Figure 1-8 shows the depth to basement. This map is calculated from the depth to the metamorphic and igneous rocks that are under the Mesozoic sediments. The thickness of the organic-rich shale is shown in Figure 1-9. Both of these maps are plotted using meters (30 meters ~ 100 feet).

Figure 1-8. Map of the depth to basement of the Sanford sub-basin. The dark blue to purple region, which is under Seismic Line 113, indicates the deepest part of the basin is 7,100 feet below the surface. Another deep point in the sub-basin is found in Moore County. The units are in meters and each color ramp indicates 100 meters (i.e. ~300 feet).

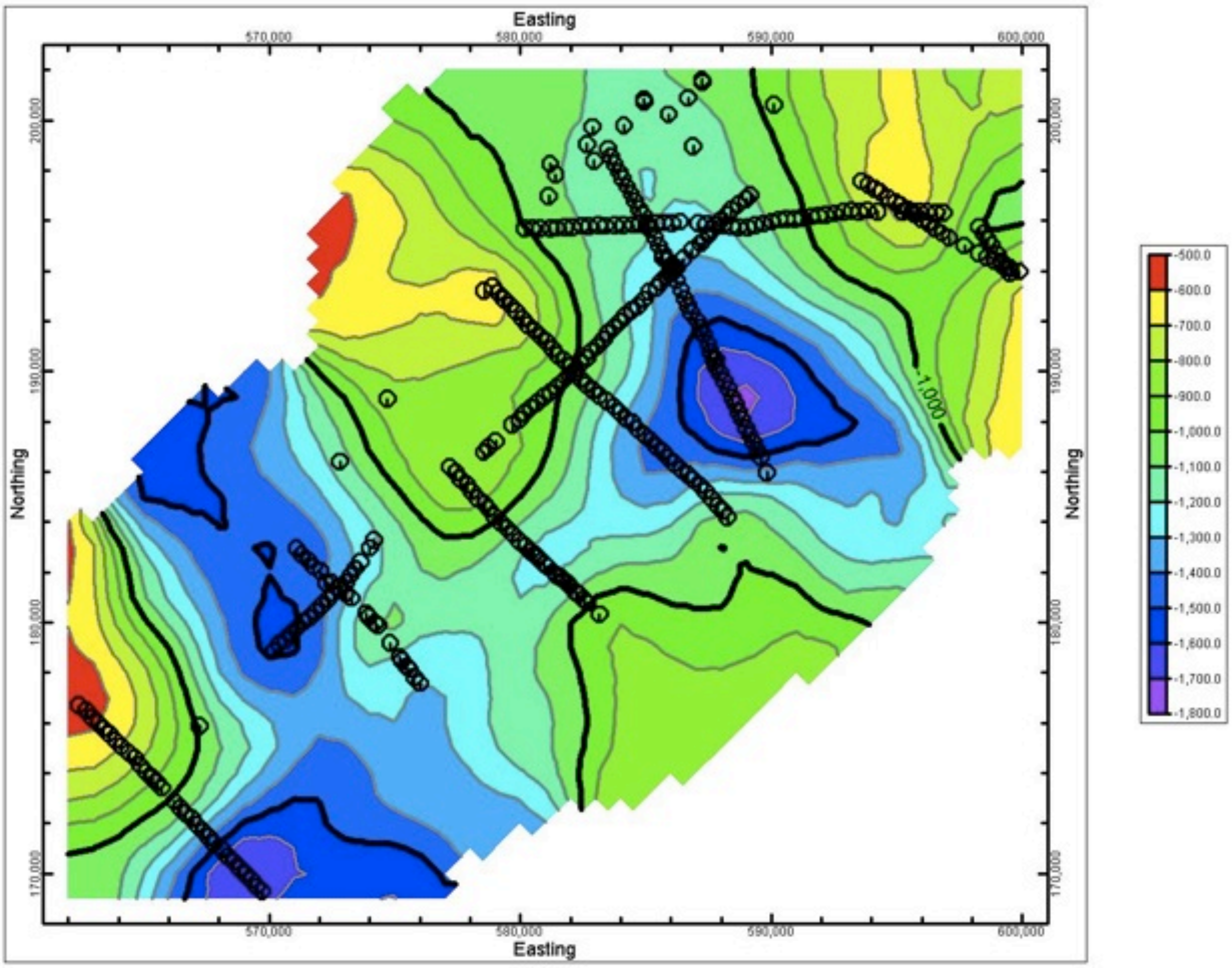
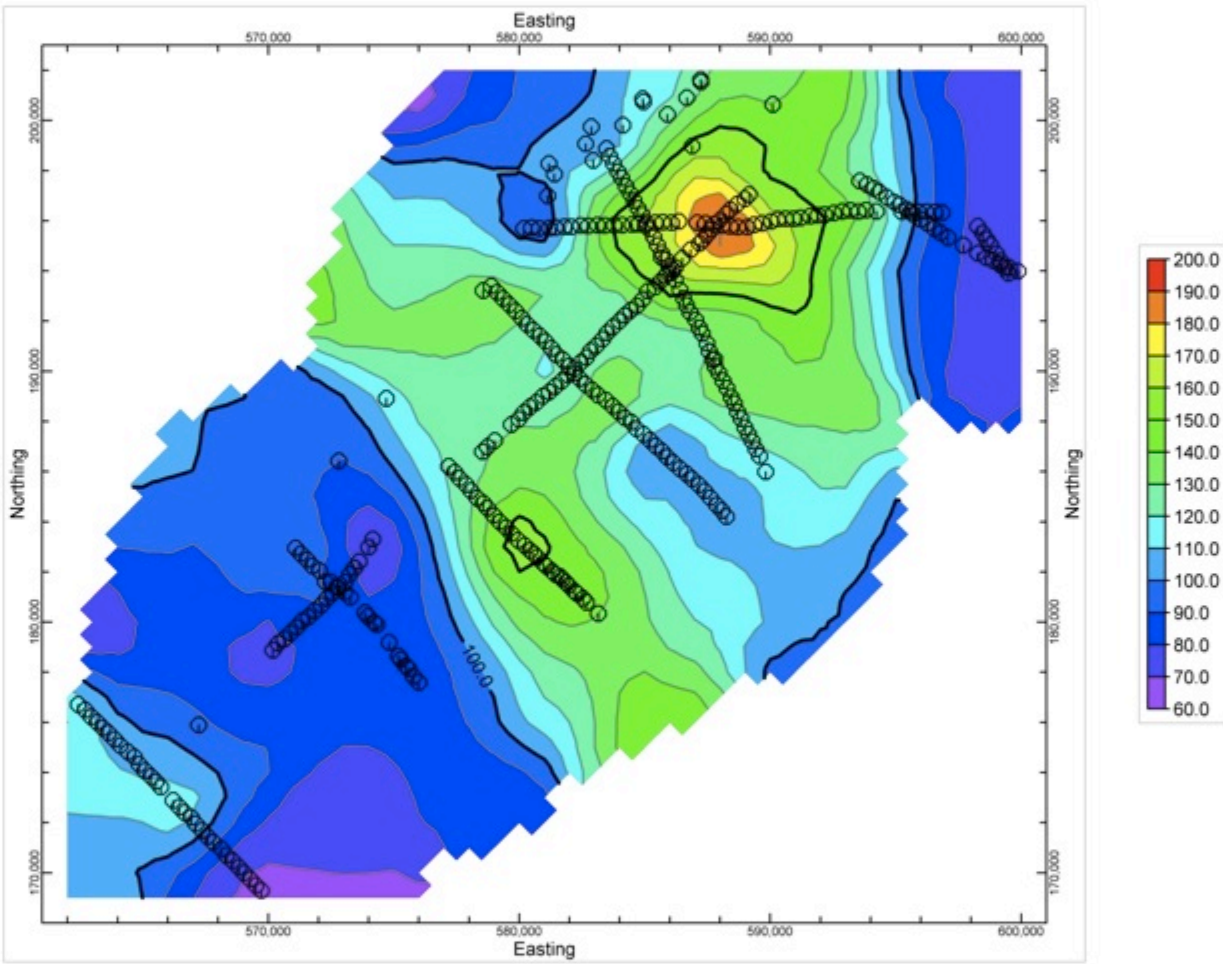


Figure 1-9. Map of the thickness of the organic-rich shale (Cumnock Formation) in the Sanford sub-basin. The units are in meters and the average thickness ranges from 60 meters (~180 feet) to 180 meters (~540 feet).



C. Estimating the resources

2012 USGS resource assessment

In 2010, DENR provided data collected and analyzed by the North Carolina Geological Survey to the U.S. Geological Survey (USGS) for use in a national resource assessment of Mesozoic basins across the United States. USGS provided a modest grant to the N.C. Geological Survey to convert paper records in the NCGS archive (geophysical logs, maps, reports, seismic lines, geochemical analyses and lithologic logs) to digital form.

The N.C. Geological Survey completed conversion and analysis of the information in December 2010. On July 12-13, 2011, Dr. Jeff Reid, the principal research geologist on this project, and Mr. Jim Simons, State Geologist, briefed USGS on the North Carolina data as part of the USGS geological assessment of Mesozoic resources.

The second phase of the USGS resource assessment is a numerical modeling method used to conservatively estimate the number of wells that can generate 0.02 bcf over the lifetime of the wells. USGS uses a rigorous, science-based methodology to assess the amount of technically recoverable natural gas; the methodology is conservative in approach. The term "technically recoverable gas" refers to the total amount of gas that is estimated to exist. Only about 20 percent of this gas can actually be recovered using existing technology.

According to the USGS, the numerical assessment should be completed in the early summer of 2012. The full resource assessment should be published in late 2012 or early 2013 and will provide the most rigorous assessment of the potential shale gas resource in North Carolina.[8]

> **Gas Resource Terms**
>
> **Technically recoverable gas:** The total amount of a resource, both discovered and undiscovered, that is thought to be recoverable with available technology, regardless of economics.
>
> **Original gas-in-place:** The entire volume of gas contained in the reservoir, regardless of the ability to produce it.

1995 USGS oil and gas resource assessment

In 1995, USGS published the results of a three-year study of the oil and gas resources of the United States. Different methodologies were used depending on the type of resource field. More information on the methodology and background for the study can be found at http://pubs.usgs.gov/circ/1995/circ1118/execsum.html.

This study includes an estimate of the "technically recoverable gas" for the Piedmont region of the East Coast. The Piedmont region included all Mesozoic rift basins along the east coast of the United States – Hartford-Deerfield (Mass.,, Conn.), Newark (N.Y., N.J., Pa.), Gettysburg (Pa., Md.), Culpeper (Md., Va.), Taylorsville (Md., Va.), Richmond (Va.), Dan River-Danville (Va., N.C.), and Deep River (N.C., S.C.). At the time of the assessment, none of these basins were producing shale gas. The USGS estimates ranged from a high of 1.19 trillion cubic feet of gas (Tcfg) to a low of 0 Tcfg; the mean was 0.39 Tcfg. Applying a recovery rate of 20% to the high estimate of 1.19 trillion cubic feet of gas, the estimated recovered gas volume would be 238 billion cubic feet of gas.

The 1995 USGS estimate covered the entire Piedmont region of the East Coast from Maine to Georgia. USGS did not assign specific values to individual basins within the region. As a result, the 1995 estimate cannot be used to develop a reliable estimate of technically recoverable gas in the Triassic Basin.

North Carolina Geologic Survey gas recovery estimates

DENR had hoped to use the 2012 U.S. Geological Survey assessment as the source for an estimate of recoverable shale gas resources in North Carolina. Since the USGS assessment is not yet complete, DENR used the limited state data available to create an estimate for use in this report. DENR's preliminary estimate has been based on data from the only two data points

[8] Email by Brenda Pierce, USGS to James Simons, January 31, 2012.

available that are both in the Sanford sub-basin. This estimate is likely to change once more data become available.

As noted above, the term "technically recoverable gas" refers to the total amount of gas that is estimated to exist. Only 20 percent of this gas can actually be recovered using existing technology. For purposes of the economic assessment, DENR has recommended using 20 percent of any estimate of technically recoverable gas as an estimate of the amount of gas that could actually be produced.

Recent data from the Butler #3 and Simpson #1 wells

The North Carolina Geological Survey has developed a preliminary estimate of the amount of technically recoverable gas based on data from two wells in the Sanford sub-basin. This estimate is only applicable to the Sanford sub-basin (an area of approximately 59,000 acres) and cannot be generalized to the entire Triassic Basin of North Carolina. Even for the more limited geographic area, two wells is a very small sample size and the estimate will very likely change once more data becomes available.

Based on just these two wells, the N.C. Geological Survey has estimated 4.2 Bcfg of technically recoverable gas or total gas per well. Accounting for the 20 percent actual recovery rate, the estimated amount of gas that could be produced from each well would be 840 x 10^6cfg. Both the estimate of technically recoverable gas and the estimate of produced gas represent an averaging of data from the two wells. Given the small data set and the fact that the data from the individual wells varied significantly, it is not clear how representative these averages would be of the gas resource in the entire Sanford sub-basin.

Subject to the limitations noted above, DENR has used this data to estimate the volume of gas that could be recovered for the entire Sanford sub-basin by multiplying the amount of recovered gas by the number of wells that could be drilled in the basin. Other sections of this study use two possible well spacing scenarios: wells drilled at 60-acre spacing and wells drilled at 160-acre spacing. To estimate the amount of recoverable gas in the Sanford sub-basin, DENR used the more conservative assumption of 160-acre spacing.[9] At 160-acre spacing, 368 wells could potentially be drilled in the Sanford sub-basin, for a volume of recovered gas of 309 Bcfg for the 59,000-acre area. These estimates of both total number of wells and volume of recovered gas have been used as a reference point in other parts of the study.

Test drilling for better data

One way to collect additional data on North Carolina's shale gas resource would be to drill some new test wells– all vertical and without hydraulic fracturing – in order to obtain additional crucial information on the extent and richness of the potential. Some of this drilling would use much smaller rigs than are used in production, because the drill diameter is much smaller. This drilling program would collect new data by sampling while drilling to estimate the total in-place gas. A portable wet laboratory with gas sampling would be required to obtain this information.

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[9] 60-acre well spacing could result in larger volumes of recovered gas, but the potentially greater volume of recovered gas would come at a higher cost of drilling.

It may be possible to conduct this research through a public-private partnership involving government, industry, and academia.

D. Anticipated industry behavior

Leasing of mineral rights

Leasing for oil and gas in the Triassic Basins has occurred several times since the early 1970s. The last eight wells drilled in North Carolina were in the Sanford sub-basin. In 1973, Chevron leased 27,850 acres in preparation for drilling. Chevron drilled several wells in the following years, although activity paused for as long as nine years between wells.

After LE-OT-01-91 (Butler #2) was drilled in 1990, there was a break of eight years before Amvest drilled the last two North Carolina wells in 1998 – LE-OT-01-98 (Simpson #1) and LE-OT-02-98(Butler #3). The last eight wells drilled in the state have been in the Sanford sub-basin. The history has been one of very limited drilling activity within a confined geographic area. Drilling has occurred in short bursts, often separated by several years of inactivity. The lack of sustained activity indicates that the exploratory drilling for oil, coalbed methane and gas did not identify a resource that was considered commercially viable given the limited drilling that occurred.

Since 2010, representatives from exploration/production companies have visited the NCGS to review the state's accumulated data. In March 2010, the first leases were signed in Lee County. At the present time, four companies have signed leases in Lee County: Whitmar Exploration Company, Hanover NC LLC, NC Oil and Gas LLC, and Tar Heel Natural Gas LLC.

Whitmar has signed 65 agreements, but two of the leases have been released. Those leases covered 124.29 Acres (Ac) and 10.119 Ac. The company has 63 agreements still in force; those leases cover a total acreage of 5,958.41 acres. Fifty-nine of the 65 leases were signed between March and June 2010. Another company, Tar Heel Natural Gas LLC, signed only one three-year Memorandum of Oil and Gas Lease for 940.72 Ac; that lease expires September 2013.

Hanover NC LLC had signed leases for 981 Ac between March 2006 and May 2008; those leases were signed before the first NCGS presentation on the shale gas potential in 2009. All of the 2006 Hanover leases, which were five-year leases, have expired. Only one lease for 628 acres remains in force. NC Oil and Gas LLC created 14 partnership agreements covering a total of 1,769.75 Ac. As of Mar. 1, 2012, all of the companies combined have 79 agreements with total acreage of 9,296.87 Ac.

Exploration can start most easily with large blocks with a single mineral rights owner. Several companies have lease agreements covering more than 160 acres (the acreage assumed for a single well). Whitmar has five lease agreements that each cover a lease block of more than 160 contiguous acres. Within those five lease blocks, Whitmar could install a total of 21 wells. (All estimates of the number of potential wells will be based on a 160-acre footprint for each well). NC Oil and Gas LLC also has five agreements and five lease blocks of more than 160 acres in size, but only six wells can be placed in that acreage. Hanover LLC has one agreement with one lease block of more than 160 acres; four wells could be placed in that lease block. Tar Heel Gas

LLC has one agreement with two lease blocks; each could have one 160-acre well. A total of 33 wells could be sited on these large lease blocks.

Note that 160-acre well spacing is common, but not uniform across the oil and gas producing states. In *Modern Shale Gas Development in the United States: A Primer*, 160-acre well spacing units are listed as one of the standard well spacing units for four of seven shale plays discussed.[10] The number and configuration of wells depends on a number of factors, but in the industry today, shale gas is extracted using horizontal drilling and fracturing of the rock to release as much of the tightly held gas as possible. The use of horizontal drilling and the increasing length of the drilling laterals may argue for greater distances between wells than required in some states.

Commercial interest

One controlling factor in the exploration for hydrocarbons in North Carolina will be industry interest and the willingness to send drilling rigs to the state. Drilling rig counts are updated daily and tracked by the oil and gas industry as a measure of activity. With the number of producing fields, the rigs are very busy and wells are being planned several months in advance. Logic would suggest that rigs working on a producing field would stay in that field as long as it is economically viable. A natural gas company is not likely to move a drill rig from a producing field to an area with unknown resource value.

Drilling also requires supporting infrastructure, like geophysical logging trucks, drill and casing pipe suppliers and experienced cement jobbers. These suppliers will follow the drilling companies.

[10] Ground Water Protection Council and ALL Consulting. *Modern Shale Gas Development in the United States: A Primer.* April 2009. Retrieved March 6, 2012 from http://www.fossil.energy.gov/programs/oilgas/publications/naturalgas_general/ShaleGasPrimer_Online_4-2009.pdf, p. 17.

Section 2 – Oil and Gas Exploration and Extraction

A. How hydrocarbons are generated and trapped in the Earth

Hydrocarbons 101

Hydrocarbons are naturally occurring organic compounds composed of hydrogen and carbon. The simplest form is methane (CH_4 – one carbon atom bonded to four hydrogen atoms). The three most common hydrocarbons are natural gas, petroleum and coal.

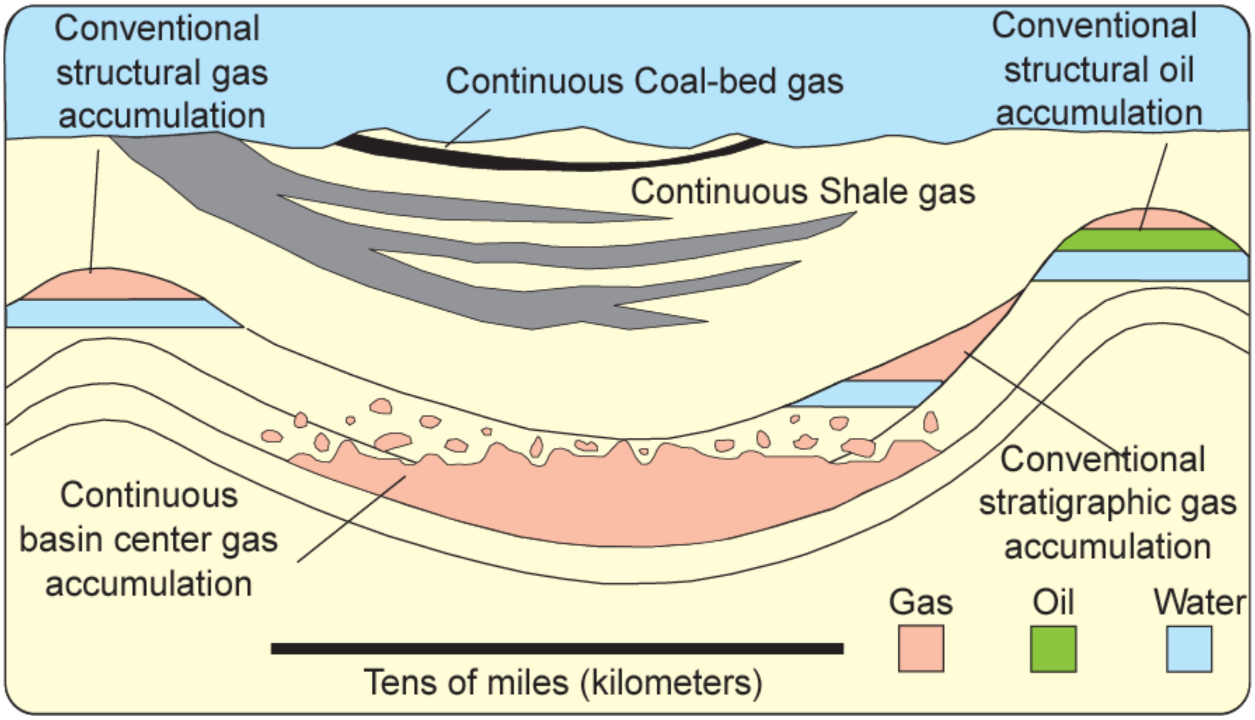
The generation of hydrocarbons starts with the organic-rich sediments. Organic matter contains kerogen, a naturally occurring solid that is insoluble in organic solvents (which means that it cannot be extracted from them). There are three types of kerogen (Types I to III). Type I is formed mainly from algae and is likely to generate oil. Type II is mixed terrestrial and marine source material, which can generate waxy oil. Type III is woody terrestrial material and typically generates gas.

The burial and heating of kerogen in the earth yields bitumen, the fraction of organic matter that is soluble in organic solvents. Further heating creates liquid hydrocarbons and hydrocarbon gas. The process of compaction and lithification or diagenesis can be measured in a geochemical laboratory by examining the type and maturity of the kerogen in a sample. If the organic-rich rock has very little kerogen, it is probably an oil source rock. If the kerogen is greater than 50 percent, then the rock is probably coal. In between these two possibilities, the rock would be a source for shale gas.

Conventional and unconventional resources

The U.S. Geological Survey (USGS) recognizes two classes of oil and gas resources: conventional and unconventional or continuous (see Figure 2-1). In a conventional resource (the industry's source of oil and gas for more than 200 years), the resource or total petroleum system is composed of three parts: the source rock, the reservoir rock and the cap rock. The source rock is the organic-rich material that has been matured by heat and pressure to create and then release hydrocarbons. The reservoir rock is a porous rock layer that contains an abundance of pore space (porosity) and interconnections between the pores (permeability) into which the oil and gas migrate. The cap rock is an impermeable layer, in which the hydrocarbons are trapped and prevented from migrating to the surface.

Figure 2-1. Model of the different types of conventional and unconventional oil and gas resources. The three continuous or unconventional accumulations are coal-bed gas, shale gas and basin-centered gas.



In the conventional model, the cap rock can be part of either a structural or stratigraphic trap. A structural trap is where the rocks have been either folded into a dome or anticline, or when the rocks are offset by a fault. As seen in Figure 2-1, the domes or anticlines are the areas where the oil and gas have pooled. A stratigraphic trap is one where the lithology, or type of rock, changes and the hydrocarbons in the reservoir rock can no longer migrate upward. One example of such as trap is when the reservoir rock changes from porous sandstone to cemented sandstone or to impermeable shale.

Unconventional or continuous oil and gas resources differ from conventional sources because there are only two parts: source/reservoir rock and cap rock. Coal-bed methane is an example of a continuous resource because the methane is found in the existing coal seam. Shale gas and shale gas liquids are another unconventional resource as long as the gas or liquid remains in the shale rock. If the gas or liquid migrates out of the source rock, then it becomes a conventional resource.

B. Methods used to find hydrocarbons

Since the subject of this report is shale gas, the discussion of methods to find hydrocarbons will focus on the unconventional or continuous oil and gas resources such as coal-bed methane, shale gas and shale gas liquids.

Knowledge of organic-rich shale rock in the United States has been part of the basic education of geologists for more than 100 years. A 2009 report, *Modern Shale Gas Development in the*

United States: A Primer by the Ground Water Protection Council and ALL Consulting for the U.S. Department of Energy and the National Energy Technology Laboratory,[11] identified 27 shale gas basins were identified (see Exhibit 7 in *Modern Shale Gas Development in the United States: A Primer*). The authors discuss seven shale formations in detail, Barnett Shale in the Forth Worth Basin, Fayetteville Shale in the Arkoma Basin, Haynesville Shale in the Texas and Louisiana Basin, Marcellus Shale in the Appalachian Basin, Woodford Shale in the Anadarko Basin, Antrim Shale in the Michigan Basin and New Albany Shale in the Illinois Basin. The ages of these shale rocks range from middle to late Devonian to Mississippian to Jurassic, spanning more than 230 million years.

In geologic terms, "basin" refers to a low area in the earth's crust, formed by the warping of the crust from mountain building forces, in which sediments have accumulated. Such features were drainage basins at the time of sedimentation but are not necessarily so today.[12] Before the late 1960s, the mechanism by which the crust would down warp (bend downwards) and create a shallow sea was not fully understood. When the concept of plate tectonics was introduced in the late 1960s, a planetary-scale model showed the earth's crust broken into a dozen or so plates. The plates separate where convection in the solid mantle drives the formation and movement of the continents and oceanic crust.

Gravity and magnetic characteristics

Shale is a sedimentary rock composed of clay-size particles that are mainly quartz. This fine-grained rock formed from mud that settled out of a water column into a lake or mud flat along with other organic matter, and then accumulated in a geologic basin.

The edge of a basin and the location of the deepest part of a basin can be delineated by the difference in density or magnetic characteristics between the original rocks and the sediment that filled the basin. Portable gravimeters, geophysical instruments that can measure differences of 1/1000th of the pull of gravity, can be used to map the edge of basins and show where the steepest down warping is located. In addition, aerial and ground-based magnetometers can measure minute changes in the magnetic field of the earth due to the interaction of magnetic minerals in rocks nearby.

Seismic reflection

Another geophysical technique used is the collection of seismic reflection data to estimate the properties of the Earth's subsurface from reflected seismic waves. In this method, vibrations from explosions or a truck-mounted mechanical system send sound waves into the earth and an array of geophones record the ground vibrations from the waves reflecting off the rock layers buried thousands of feet below. After processing, the seismic reflection profile will illustrate a vertical slice into the earth where the vertical axis is not depth in feet, but rather the two-way travel time of the generated sound waves. Figure 2-2 shows Seismic Line 113 across the Sanford sub-basin of the Deep River Basin in North Carolina. To better see the

[11] Ground Water Protection Council and ALL Consulting, 2009.

[12] Bates, R. L. and Jackson, J. A. (editors) (1984). Dictionary of Geological Terms – Third Addition, American Geological Institute, Garden City, NY.

interpretation of the measurements, Figure 2-3 shows the seismic line without the reflectors and only the interpretations. The coloring and highlights are the same in both Figures 2 and 3.

Figure 2-2. Seismic Reflection Line 113 across the Sanford sub-basin, Deep River Basin. The line was collected by recording a series of dynamite explosions across the basin going from the northwest (left side) to the southeast (right side). The interpreted reflectors are highlighted in green and the offsets on the reflectors are shown in red and are interpreted to show the location of faults at depth. The purple colored vertical line shows the estimated total depth of the basin to be 7,000 feet. The Bobby Hall #1 well intercepted the organic-rich Cumnock Formation at the orange colored highlight section of the well.

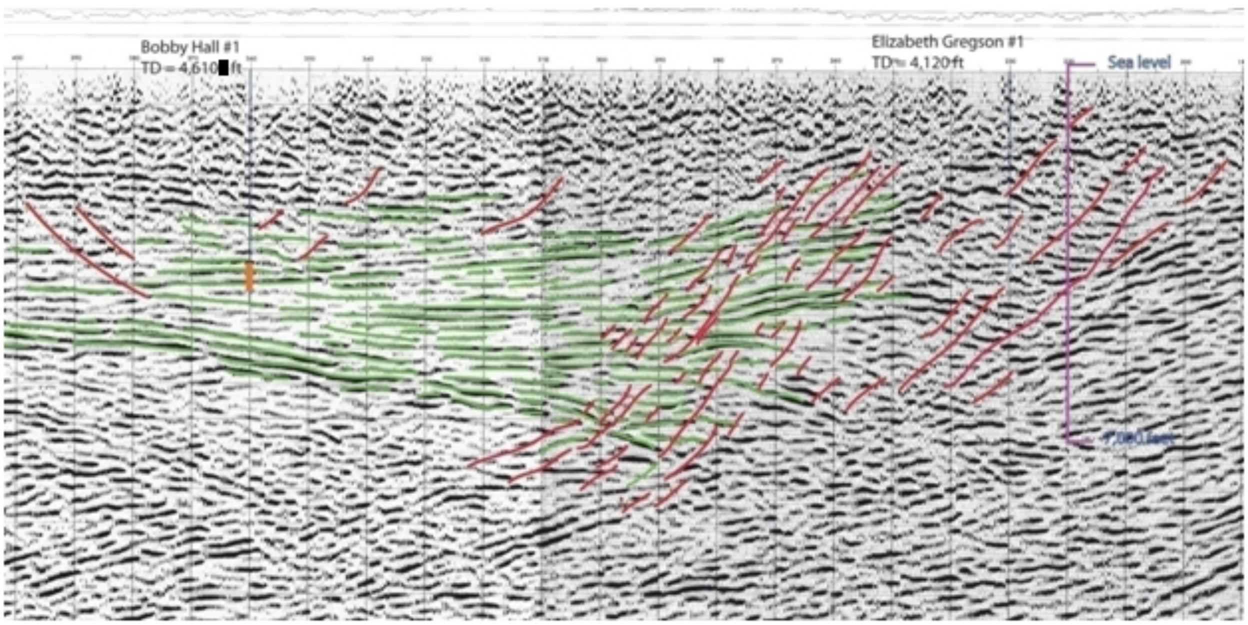
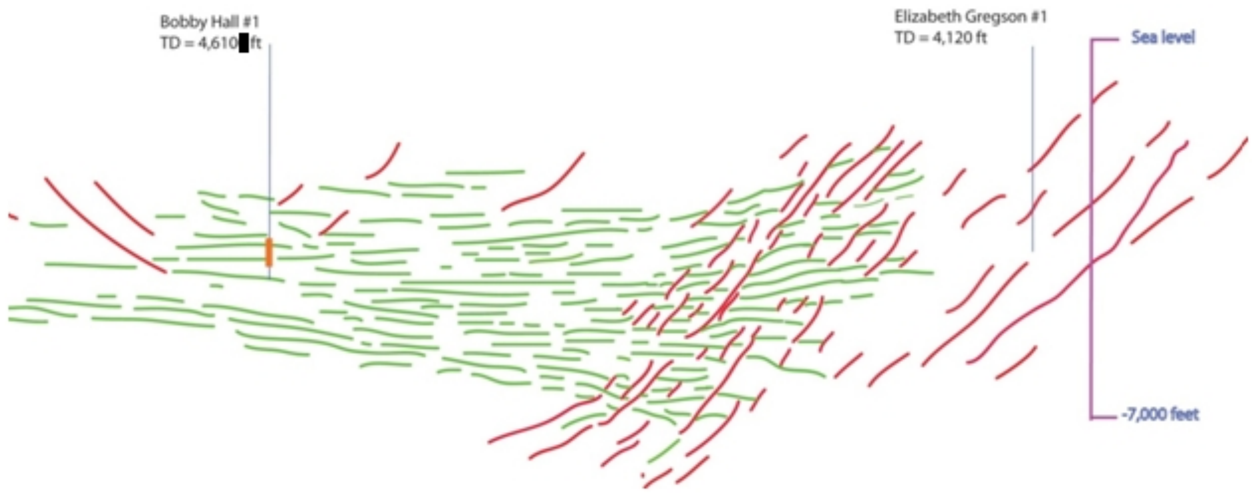


Figure 2-3. Interpretation of Seismic Reflection Line 113 across the Sanford sub-basin, Deep River Basin. The interpreted reflectors are highlighted in green and the offsets on the reflectors are shown in red and are interpreted to show the location of faults at depth. The purple line shows the estimated total depth of the basin to be 7,000 feet. The Bobby Hall #1 well intercepted the organic-rich Cumnock Formation at the orange colored highlight section of the well.



Organic geochemistry indicators

Geochemical analyses of organic-rich shale rock can answer three questions. The first question: is there enough organic material in the rock to generate oil or gas? Using kerogen in the rock, an analysis is made to determine the total organic carbon content (TOC %) and its bulk isotopic composition. A conservative threshold of TOC greater than 1.4 percent is the minimum level of organic carbon to generate hydrocarbons.

The second question has to do with the type and maturity of the kerogen. As discussed in Section 1, the maturity of the kerogen determines whether rock containing hydrocarbons will produce methane, oil or gas. To answer the question, a technique called Rock Eval Pyrolysis is commonly used to quantify the amount of hydrocarbon, the amount of hydrocarbon generated by heating the sample, the amount of carbon dioxide generated during the heating process, and the temperature at which the maximum release of hydrocarbons occurs during heating. A discussion of the results of similar tests is presented in Section 1 of this report for samples of Triassic rocks from North Carolina.

In prospecting for shale gas, typically fresh samples taken along road cuts or outcrops as well as samples from diamond core drilling or cuttings would be examined. Taking samples across from the darkest layers, one would obtain from a geochemical laboratory the measurement of TOC %. Values below the 1.4 percent threshold indicate there is not enough kerogen to produce oil or gas.

For samples with TOC % greater than 1.4 percent, the Rock Eval Pyrolysis test would then be run to show the type of kerogen and the temperature at which the maximum release of hydrocarbons occurs. This temperature is called Tmax. As one can see in Section 1 of this report, Tmax shows where an individual sample falls within one of five windows: immature (not maturated enough), oil, wet gas, dry gas and overmature. Because of the intrusion of igneous dikes and sills into the Triassic Basins, some shale rock has been overcooked and the oil or gas has been destroyed by the high temperature. In other cases, the shale rock is too far from these intrusives and the rock had not been cooked enough.

Two other terms are also used to quantify the results from the Rock Eval Pyrolysis: thermal alteration data (TAI) and vitrinite reflectance data (%Ro). Both indicate levels of thermal maturity suitable to generate hydrocarbons.

C. Methods to extract hydrocarbons

Process of shale gas development

Development of a shale gas resource involves eight distinct steps: 1) mineral leasing, 2) permit acquisition, 3) road and pad construction, 4) drilling and completion, 5) hydraulic fracturing, 6) production, 7) workovers and 8) plugging and abandonment/reclamation. [13] There is an expected duration for each step.

Mineral leasing will take several weeks and continue for years during the development of a field. The leases are private contracts between the exploration/production company and the individual mineral rights holder. Mineral rights may or may not be owned by the surface landowner. If mineral rights have been severed from the surface estate, the contract will generally indicate how the surface landowner will be compensated for the use of the surface estate to obtain the minerals from the subsurface estate.

Once the land holdings have been secured by the exploration/production company, **permits** will be obtained to authorize the drilling of a new well and a bonds may be required to ensure compliance with state standards. In North Carolina, an erosion and sedimentation control plan must be approved prior to drilling. In North Carolina (as in other oil and gas producing states), the driller would also require a well construction permit and an oil or gas drilling permit. The need for other state approvals depends on the actual impacts of the drilling operation and the methods to be used for managing stormwater, wastewater, and other drilling wastes. In most oil and gas producing states, the driller would need a permit or other approval to withdraw water for the drilling process.

Once all permits have been secured, clearing and construction will begin for the **access road and drilling pad**. This step takes several days to weeks to complete.

The next step is **drilling and completion** of the well. The largest driving force in the timing of shale gas development is the availability of the drilling rig. The number of drilling rigs working throughout the U.S. is tracked on a daily basis. Rigs may be scheduled months to years in advance. Building the drill pad and clearing the access road are usually timed to precede the arrival of the rig by only a week or two. Once the rig is “on-station,” drilling will be a 24-hour a day operation. Several layers of casing (steel pipe placed in the hole and cemented or grouted

[13] Ground Water Protection Council and ALL Consulting, 2009.

to the surrounding rock) are pumped into the well bore. The cement and steel casing provide multiple layers of protection to the groundwater from the drilling process. Once the hole has reached the total depth (TD), the well is fully cemented to the surrounding rock.

For horizontal drilling, the vertical drilling stops approximately 500 feet above the horizon where the well bore will start to be horizontal. The standard drill bit is replaced with a steerable drilling head that can be driven to change the well bore from vertical to horizontal. The transition takes about one-quarter mile (~1,300 feet). Drilling continues with the steerable drill head until the total length of drilling is completed. The drilling pipe is removed and steel casing is lowered into the hole. Cement is pumped into the well and out the shoe at the end of the pipe and cement or grout fills the annulus between the casing and the surrounding rock.

Hydraulic fracturing is the next step. Before fracturing, holes are made in the steel casing and grout using a perforating gun. That device is lowered to specific depth and fired. A number of shaped charges positioned along the length of the gun are set off by detonation cord. The shaped charges will blast holes through the steel casing and ground and then shatter the surrounding rock.

Once the well is perforated, packers (expandable rubber baffles) are placed along the horizontal well bore starting at the point from the vertical segment of the well. This process permits the hydraulic fluid, composed of water, proppant (usually sand), and a small percentage of chemicals, to be pumped into the isolated portion of the well bore and fracture the surrounding rock. Each stage is approximately 350 feet in length. The hydraulic fracturing process is well documented in the 2009 report, *Modern Shale Gas Development: A Primer,* and in a 2012 report from the Energy Institute at the University of Texas at Austin.[14]

Once the hydraulic fracturing is completed, the well is ready to be placed into production. One additional factor that can affect the beginning of production is the availability of infrastructure between the gas wells and the existing pipeline. Hundreds of completed wells are inactive while exploration/production companies wait for construction of feeder pipelines and other processing infrastructure to be built.

To compare vertical wells with variable fracturing treatment to recent horizontal hydraulically fractured wells, the USGS Eastern Energy Resources Science Center provides this narrative:

> "Old style (vertical well, variable frac treatment) Devonian shale wells (in the '70s) produced about 4,000 cubic feet of gas per day for over 20 years. Modern Marcellus wells in PA produce about 2 to 3 million cubic feet of gas per day after about a 10 - 15 day clean up, or about a thousand times that of the old Devonian well production. It appears that these wells will decline rapidly to about 250,000 cubic feet per day in 10 years. This type of well ultimately produces about 2 billion cubic feet of gas over 10 years..."[15]

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[14] Groat, C.G., Grimshaw, T.W. "Fact-based regulation for environmental protection in shale gas development – summary of findings." The Energy Institute, The University of Texas at Austin, 2012. PDF copies found at http://energy.utexas.edu/.

[15] Coleman, J.L. Written communication of June 16, 2011 to Jeff Reid, N.C. Geological Survey.

From this narrative, the following calculations are made:

Production from old style vertical wells --

4,000 cfg/day x 365 days/year = 1.46 million cubic feet/year or 1.46 MMcfg/year

1.46 MMcfg/year x 20 years = 29 MMcfg total recovered gas.

Production from modern horizontal hydraulic-fractured wells –

2 – 3 MMcfg x 365 days/year = 730 – 1,095 MMcfg/year

The modern wells are producing 500 to 750 times more gas per year.

The two remaining steps in shale gas development are workovers and the plugging of the well and abandonment/reclamation processes. **Workover** is the process of cleaning, repairing and maintaining the well for the purpose of increasing or restoring production. Multiple workovers may be performed over the life of the well and each workover will take several days to weeks to perform.

When a well reaches its economic production limit, the well is brought off-line for **plugging and abandonment/reclamation** following state standards. Currently in North Carolina, the operator applies for a permit to plug and abandon the well where the well must be cemented completely from bottom to top and all pits filled, and the site restored as required in the original oil and gas drilling permit. Once plugged and abandoned in accordance with a field inspection, the bond on the well would be released.

Alternative fracturing techniques

In areas where water for hydraulic fracturing is limited or the outside temperatures remain below freezing for a substantial part of the year, a new technique has been developed in Canada to use liquefied petroleum gas (LPG) or propane in a gel or foam as a substitute for water.

GasFrac Energy Services in Calgary, Alberta, developed the technique of using 90 percent propane with a gelling agent so that the liquid propane would have the thickness or viscosity to carry the chemical and sand proppant.[16] The well fracturing is performed in stages, just like hydraulic fracturing, but when the fracturing occurs, the gel breaks and the propane turns to a vapor to be captured as a constituent of the released natural gas.

GasFrac Energy Services is still awaiting a U.S. patent but, since first testing the product in 2008, they have used the technique of hydraulically fracturing with propane gel around 1,000 times in the Canadian provinces of Alberta, British Columbia and New Brunswick and at a handful of test

[16] Milmo, S. "Fracking with propane gel." Royal Society of Chemistry, November 15, 2011. Retrieved March 6, 2012 from http://www.rsc.org/chemistryworld/News/2011/November/15111102.asp.

wells in Texas, Pennsylvania, Colorado, Oklahoma and New Mexico.[17] The two advantages of this technique are 1) the propane flashes to a gas and is incorporated into the natural gas production and 2) there are no waste fracturing fluids to carry the drilling chemicals, salty brines and radioactivity back to the surface.

Two drawbacks to this technique are the lack of published results of the hydraulic fracturing technique and the 20 to 40 percent greater cost. Two major savings that have not been calculated are: 1) reduced costs of handling and disposing of used fracturing fluid and 2) the completely recovered propane that can be reused or sold.

[17] Brino, Anthony and Nearing, Brian. "New waterless fracking method avoids pollution problems, but drillers slow to embrace it." InsideClimate News, November 4, 2011. Retrieved November 6, 2011 from http://insideclimatenews.org/news/20111104/gasfrac_propane-natural-gas-drilling-hydraulic-fracturing.

Section 3 – Potential infrastructure impacts

A. Water supply

This analysis of water availability focuses on the areas around the geologically defined Dan River Triassic Basin and the Deep River Triassic Basin. The use of the terms “basin” and “sub-basin” in geologic terms is inconsistent with how these terms are used in reference to water resources. Therefore, when the geologically defined areas are being discussed they will be denoted as Triassic or geologic basins and when the hydrologically defined areas are discussed they will be denoted as hydrologic basins. Maintaining this distinction is important because water use and water availability data are compiled, evaluated and summarized by hydrologically defined boundaries.

Data on water availability data are typically collected and summarized using a nested hierarchy of surface water drainage areas adopted by the United States Geological Survey (USGS) and the Natural Resources Conservation Service of the U.S. Department of Agriculture. This system, shown in Table 3-1, designates the Upper Dan River sub-basin as hydrologic unit 03010103 and the Deep River sub-basin as hydrologic unit 03030003.[18] These geographic areas are further subdivided into smaller watersheds designated by 10 digit labels and subwatersheds designated by 12 digit labels.

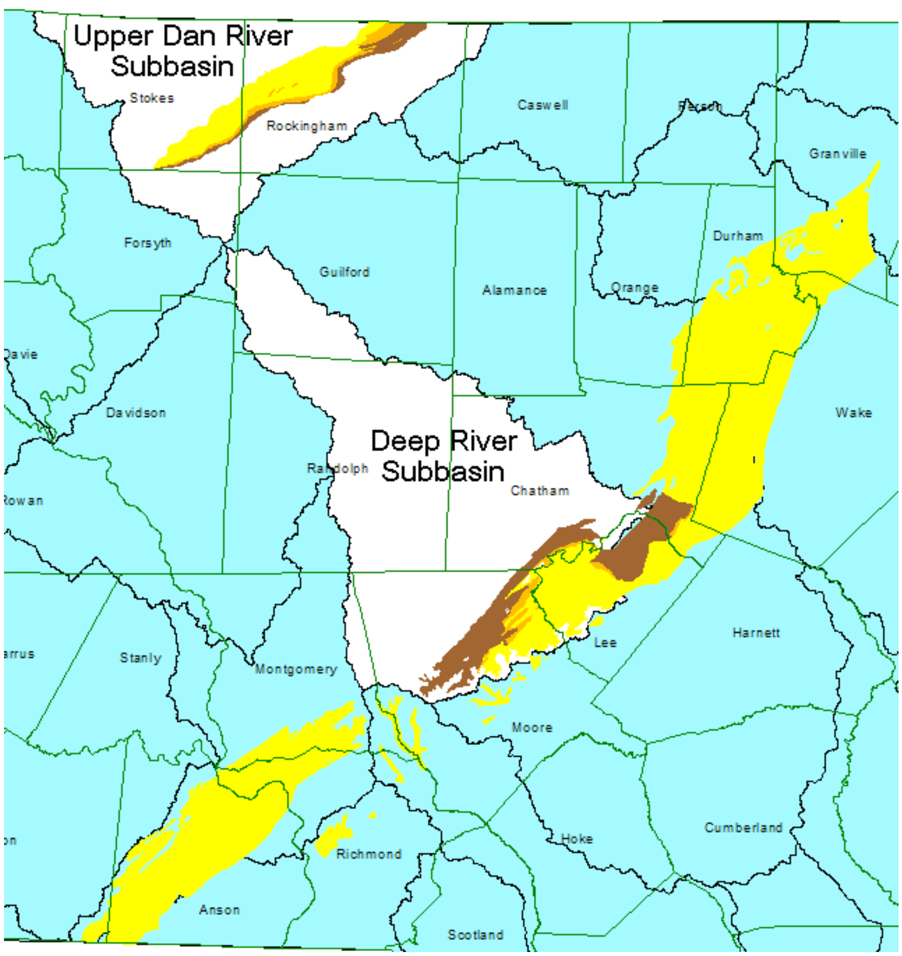
Figure 3-1 shows the Triassic Basins with the extent of the component formations shown in yellow, orange, and brown in relation to the Upper Dan River and the Deep River hydrologic sub-basins shown in white. Study areas are delineated by groupings of hydrologically defined subwatersheds. The groupings of subwatersheds encompassing the Triassic Basins and defining the study areas for water resource evaluations are delineated by the black lines in Figure 3-2.

[18] U.S. Geological Survey and U.S. Department of Agriculture, Natural Resources Conservation Service, 2011, Federal Standards and Procedures for the National Watershed Boundary Dataset (WBD) (2d ed.) U.S. Geological Survey Techniques and Methods 11-A3, 62p. Available on the World Wide Web at http://pubs.usgs.gov/tm/tm11a3/

Table 3-1. USGS Drainage Area Nomenclature[19]

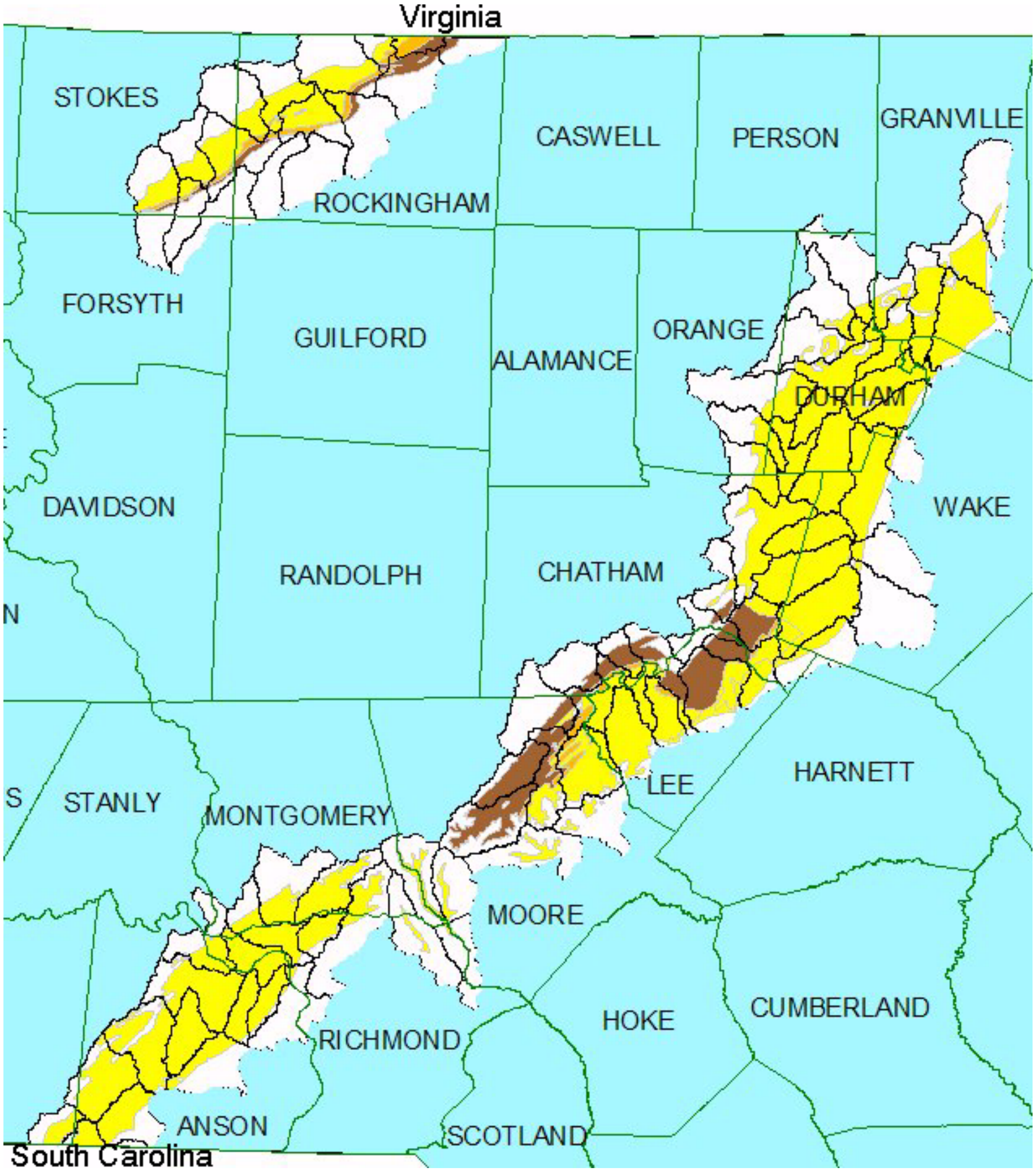
Current numerical name	Digits in hydrologic unit code	Common name	Hydrologic unit level	Average size (square miles)	Approximate number of hydrologic units
2 digit	2	Region	1	177,560	21 (actual)
4 digit	4	Sugregion	2	16,800	222
6 digit	6	Basin	3	10,596	370
8 digit	8	Sub-basin	4	700	2,270
10 digit	10	Watershed	5	227 (40,000-250,000 acres)	20,000
12 digit	12	Subwatershed	6	40 (10,000-40,000 acres)	100,000
14 digit	14	(None)	7	Open	Open
16 digit	16	(None)	8	Open	Open

Figure 3-1. Triassic Basins and Upper Dan River and Deep River Sub-basins



[19] United States Geological Survey Techniques and Methods 11-A3.

Figure 3-2. Triassic Basins and Subwatersheds Used in this Analysis



Data sources

State law requires some water withdrawers to register their water use with the Department of Environment and Natural Resources. Owners of non-agricultural facilities that withdraw 100,000 gallons or more of water on any day and owners of agricultural operations that withdraw 1 million gallons or more of water on any day are required to register their withdrawals.[20] These registrations document water sources and current water usage. Some community water systems meet the registration requirement by submitting a local water

[20] N.C. General Statute 143-215.22H.

supply plan to the Division of Water Resources. All units of local government that supply water to the public and other large community water systems are required by General Statute 143-355(l) to prepare and submit a local water supply plan. The local plans describe the characteristics of the water system, such as water sources, number of connections, population served and projections of future water supply needs. Details of the water supply plan requirements and the data submitted to DENR can be found on the division's web site at www.ncwater.org. Data from these plans were used to estimate current and future water needs for existing water users for this analysis.

Water withdrawal locations and water use figures were analyzed using data collected and compiled by the Source Water Assessment Program, the Water Withdrawal and Transfer Registration Program and the Local Water Supply Planning Program, all of which are administered by the Division of Water Resources. The study areas for the Triassic Basins were defined by sets of subwatersheds that provide close geographic consistency with the Triassic Basins.

Water use and potential supply

Deep River Triassic Basin

The geologic formations in the Deep River Triassic Basin are comprised of materials deposited millions of years ago and now found in a "northeast-trending, trough-shaped downfaulted block of Triassic rocks near the east edge of the Piedmont plateau."[21] The Deep River Triassic Basin extends from the boundaries of Union and Anson counties at the South Carolina state line northeasterly into the southern portion of Granville County. Along this path the component formations underlie portions of several major surface water drainage areas including the Upper Pee Dee, Lower Pee Dee, Lumber, Deep, Upper Cape Fear, Haw, Upper Neuse and Upper Tar sub-basins. A natural break in the geologic formations near the boundary of Moore County and Montgomery County creates a convenient analytical divide in the geologic basin. The Sanford and Durham sub-basins lie north of the divide within Chatham, Durham, Granville, Lee, Moore, Orange and Wake counties. South of the divide, the Wadesboro sub-basin lies within Anson, Montgomery, and Richmond counties.

Sanford and Durham Sub-basins of the Deep River Triassic Basins

The areas encompassing the Sanford and Durham Sub-basins of the Deep River Triassic Basin are shown in Figure 3-3 in yellow, orange and brown within the water resource study area. Surface water sources for public water supply systems are indicated by blue triangles on the map and groundwater sources are shown by the green crosses. It is noteworthy that there are few public water system wells within the Triassic Basins. This may be an indication of the low yields produced by these formations, especially when compared to the proliferation of wells seen just outside of the basin boundaries in Durham, Orange and Wake counties.

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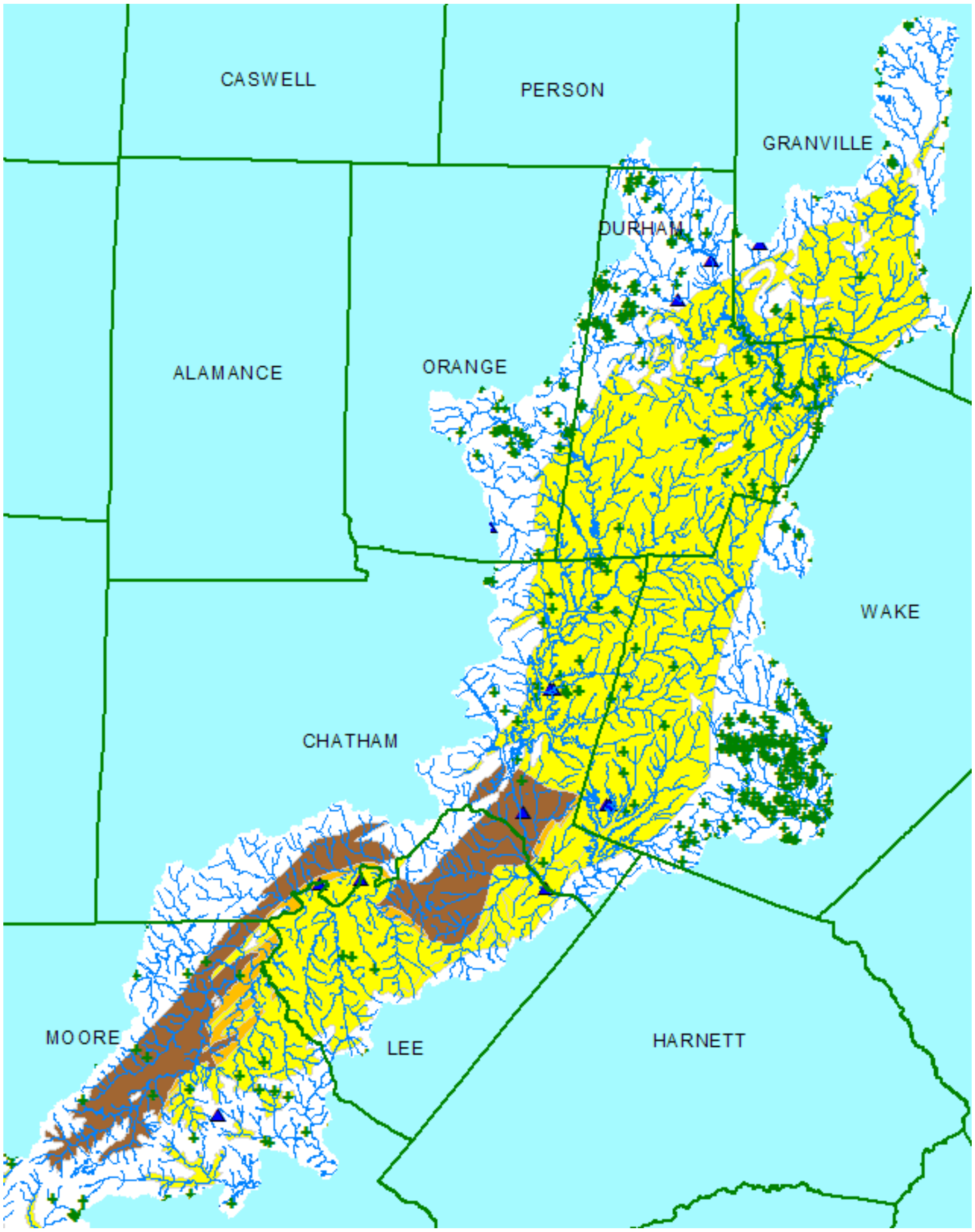
[21] Reinemund, J.A. "Geology of the Deep River Coal Field North Carolina: U.S. Geological Survey Professional Paper 246." U.S. Geological Survey, 1955, page 9.

Figure 3-3. Sanford and Durham Sub-basins and Study Area



In the Sanford and Durham geologic sub-basins the Deep River and the Haw River merge to form the Cape Fear River; all of the surface waters flowing out of these drainage areas flow through the Sanford and Durham geologic sub-basins. The lower 30 miles of the Deep River flow along the western boundary of the Triassic Basin. Natural flows in the Deep River are supplemented by water releases from several upstream reservoirs. Above the confluence, in the Haw River drainage, Jordan Lake lies inside the western boundary of the Triassic Basin in Chatham County. This reservoir, built and operated by the U.S. Army Corps of Engineers, stores water as a regional water supply source, provides flood control storage and provides water to augment downstream flows in the Cape Fear River.

In the Durham sub-basin of the Deep River Triassic Basin waters from the Eno, Little and Flat rivers flow into Falls Lake. This reservoir serves as the main water supply for the city of Raleigh's public water system and provides flood control storage and water for flow augmentation downstream in the Neuse River.

Interest in the gas-producing potential of the Triassic Basins has focused on the Sanford geologic sub-basin because historically this area has produced coal, and because existing exploratory wells indicate the presence of natural gas. Within the Sanford study area there are four local government water systems: the city of Sanford, Goldston-Gulf Sanitary District, Moore County Public Utilities – Seven Lakes, and the town of Carthage.

The city of Sanford and the Goldston-Gulf Sanitary District are supplied by water withdrawn from the Cape Fear River through a water treatment plant operated by Sanford. The Moore County Public Utilities-Seven Lakes water system distributes groundwater withdrawn from a subwatershed outside of the Triassic Basin to its customers, some of whom reside in the Triassic Basin. The town of Carthage withdraws surface water from Nicks Creek, a tributary of the Little River that is outside of the study area and the Deep River sub-basin. Overall in the Sanford geologic sub-basin study area 45 groundwater and surface water sources supply public water systems. Twenty-four of these sources tap waters within the Triassic Basin.

Within Lee County, the city of Sanford also provides water from the Cape Fear River to the Carolina Trace Water System and the town of Broadway. In 2010, these three systems provided water to almost 47,000 of the 58,059 county residents (81 percent). Residents not supplied by the network of water utilities supplied by the city of Sanford depend on private wells or other groundwater-based community water systems. At least one community water system uses water from wells in the Triassic Basin.

Until recently, the Goldston-Gulf Sanitary District in the Chatham County portion of the Sanford study area withdrew and treated water from the Deep River. In 2010, the district provided water treated by the city of Sanford to 1,250 of the 11,160 residents of the Indian Creek, Smith Creek, and Cedar Creek subwatersheds. The rest of the residents in these subwatersheds depend on private wells, some of which likely draw water from Triassic Basins. In addition to the community water systems noted, two registered water withdrawers use surface water from the Deep River in southern Chatham County; one agricultural operation and one industrial facility. There may be additional self-supplied agricultural or industrial operations that use water from the Deep River, but do not meet the threshold of use that requires them to register their water withdrawals.

Moore County lies within nine subwatersheds within the Sanford study area. The town of Carthage supplied water from outside the study area to 2,414 county residents in 2010. Moore County Public Utilities-Seven Lakes provides water to an undetermined number of customers in several of the subwatersheds within the study area. Some of the water comes from wells outside of the Triassic Basin and some water comes from Drowning Creek, in the Lumber River sub-basin, through other public water systems in the county. In addition, the Foxfire Village water system provides groundwater to customers in southwestern Moore County. In 2010 the estimated population in the nine study area subwatersheds in Moore County was about 22,000.

Residents of this area that do not receive water from the town of Carthage, Moore County Public Utilities-Seven Lakes, or the Foxfire Village water systems are dependent on other groundwater sources within the study area. An unknown number of these wells are located in the Triassic Basin.

Characterizing water use within the study areas is complicated by the inconsistency of the boundaries used to collect and summarize data. Data needed for this analysis are organized by politically defined county boundaries, hydrologically defined surface water drainage areas and the geologically defined Triassic Basins, the boundaries of which are not correlated and have different geographic extents.

The Office of State Budget and Management provides population data and projections of population changes through 2030 for counties in the state. Table 3-2 shows historic and projected population data for the counties encompassing the Sanford and Durham sub-basins of the Deep River Triassic Basin. Table 3-3 shows the expected population to be served by public water systems in these counties that submit a local water supply plan to DWR. The expected levels of water use associated with the anticipated levels of service are shown in Table 3-4. These water utilities anticipate continuing to serve more than half of the current and future residents of these counties.

Table 3-2. Sanford and Durham Sub-basins - County Population

Sanford-Durham Sub-units of Deep River Triassic formations			
County Population	Population	Population	Population
	2010	2020	2030
Chatham County	63,870	78,237	92,604
Durham County	268,925	323,474	378,024
Granville County	60,547	69,359	78,167
Lee County	58,059	65,857	73,658
Moore County	88,594	101,324	112,189
Orange County	134,325	155,442	176,559
Wake County	907,314	1,160,823	1,414,333
Total	1,581,634	1,954,516	2,325,534
(from OSBM website on January 6, 2012)			

Table 3-3. Sanford and Durham Sub-basin - Population Served by a Local Water Supply Plan (LWSP) Water System

Sanford-Durham Sub-units of Deep River Triassic formations			
LWSP Service Population	Population	Population	Population
	2010	2020	2030
Chatham County	30,853	32,886	35,266
Durham County	241,543	286,419	329,421
Granville County	31,262	36,046	44,822
Lee County	46,820	64,088	84,615
Moore County	51,101	60,112	69,474
Orange County	103,604	121,366	139,325
Wake County	688,004	964,088	1,224,617
Total	1,193,187	1,565,005	1,927,540

Table 3-4. Sanford and Durham Sub-unit - Water Demands from Local Water Supply Plans

Sanford-Durham Sub-units of Deep River Triassic formations			
LWSP Service Area Demand	MGD	MGD	MGD
	2010	2020	2030
Chatham County	5.1	6.3	7.6
Durham County	28.1	29.4	34.1
Granville County	5.7	7.8	9.7
Lee County	9.4	14.8	22.0
Moore County	8.0	9.1	10.5
Orange County	8.9	11.2	13.1
Wake County	84.5	108.1	133.7
Total	149.7	186.8	230.6

Table 3-5. Sanford and Durham Sub-basins - Population and Water Demands of County Residents Not Served by a LWSP System

Sanford-Durham Sub-units of Deep River Triassic formations			
Non-LWSP Population/Demand			
Estimated @ 75 gals/person/day	2010	2020	2030
Chatham County	33,017	45,351	57,338
Durham County	27,382	37,055	48,603
Granville County	29,285	33,313	33,345
Lee County	11,239	1,769	0
Moore County	37,493	41,212	42,715
Orange County	30,721	34,076	37,234
Wake County	219,310	196,735	189,716
Total	388,447	389,511	408,951
Estimated water needs (mgd)	29.1	29.2	30.7
zero values indicate predicted service population exceeded predicted county population			

The data in Table 3-2 and Table 3-3 suggest that, over the next couple of decades, a significant number of county residents will continue to be dependent on private wells or very small well-based community water systems. Table 3-5 estimates the number of county residents that will likely be dependent on groundwater from household or community wells, including estimates of the cumulative amount of water needed to meet those demands assuming each person uses 75 gallons of water per day.

Table 3-6. Sanford and Durham Sub-basins Agricultural Water Use

Sanford-Durham Sub-units of Deep River Triassic formations				
2010 Daily Agricultural Use	Unique	Ave. Daily	Ave. Daily	Daily
Use in million gallons per day	Operations	Ground Water	Surface Water	Capacity
Chatham County	12	0.091	*	0.956
Durham County	6	*	0.040	0.938
Granville County	19	0.425	0.346	17.876
Lee County	20	0.062	0.216	13.539
Moore County	33	*	0.537	22.508
Orange County	10	*	0.074	5.424
Wake County	41	0.143	1.477	28.822
Total	141			90.1
Data from Dept. Agriculture & Consumer Services-Agricultural Statistics Division - Water Use Survey				
* data not released -one operation is greater than 60% of total or less than 3 operations				

In addition to the registered water withdrawals and the estimated usage by individual households and small systems, at least 141 agricultural operations in these counties each withdrew 10,000 gallons of water or more on at least one day during 2010 (see Table 3-6). According to the annual survey of agricultural water users conducted by the Agricultural Statistics Division of the N.C. Department of Agriculture and Consumer Services, these agricultural operations have the combined capacity to withdraw 90 million gallons per day from unspecified locations and sources in these counties.[22] Agricultural water use varies by the type of operation and hydrologic conditions during the growing season. In many cases, agricultural operations only apply water when precipitation is inadequate to support crop development. The lack of information about these and other unregistered withdrawals makes it difficult to predict withdrawal needs and identify potential conflicts among water users.

Wadesboro Sub-basin of the Deep River Triassic Basin

Figure 3-4 shows the extent of the Triassic Basins in yellow and delineates the cluster of subwatersheds used as the study area for the Wadesboro sub-basin of the Deep River Triassic Basin. Public water system surface water sources are shown as blue triangles and groundwater sources as green crosses. This area of geologic interest extends from the southeastern corner of Union County, at the South Carolina state line, northeasterly through Anson and Richmond counties and into southern Montgomery County. The Pee Dee River, flowing south out of Lake

[22] The 2010 Agricultural Water Use Survey Report is available at: http://www.ncagr.gov/stats/environmental/WU2010.pdf

Tillery, is the major hydrologic feature within this geologic sub-basin. Lake Tillery collects runoff from 4,600 square miles of central North Carolina. Just upstream of the Wadesboro Triassic sub-basin the Pee Dee River is joined by the Rocky River, which drains an additional 1,400 square miles of Anson, Cabarrus, Mecklenburg, Stanly and Union counties. The Wadesboro Sub-basin underlies the Pee Dee River between Lake Tillery and Blewett Falls Lake. These two reservoirs are owned by Progress Energy and managed under a license issued by the Federal Energy Regulatory Commission (FERC). These reservoirs serve as the major water sources for three county water systems. East of the river, Richmond County has an intake on Blewett Falls Lake to supply its public water system. To the north, Montgomery County gets water from Lake Tillery and then distributes it throughout the county including at least one public water system in northwestern Moore County. West of the river, Anson County withdraws water from Blewett Falls Lake and distributes drinking water throughout the county to municipal water systems and county residents, many of whom reside within the boundaries of the Wadesboro Triassic sub-basin. The Anson County water system also supplies water to communities in Union County.[23]

Figure 3-4. Wadesboro Triassic Sub-basin and Study Area

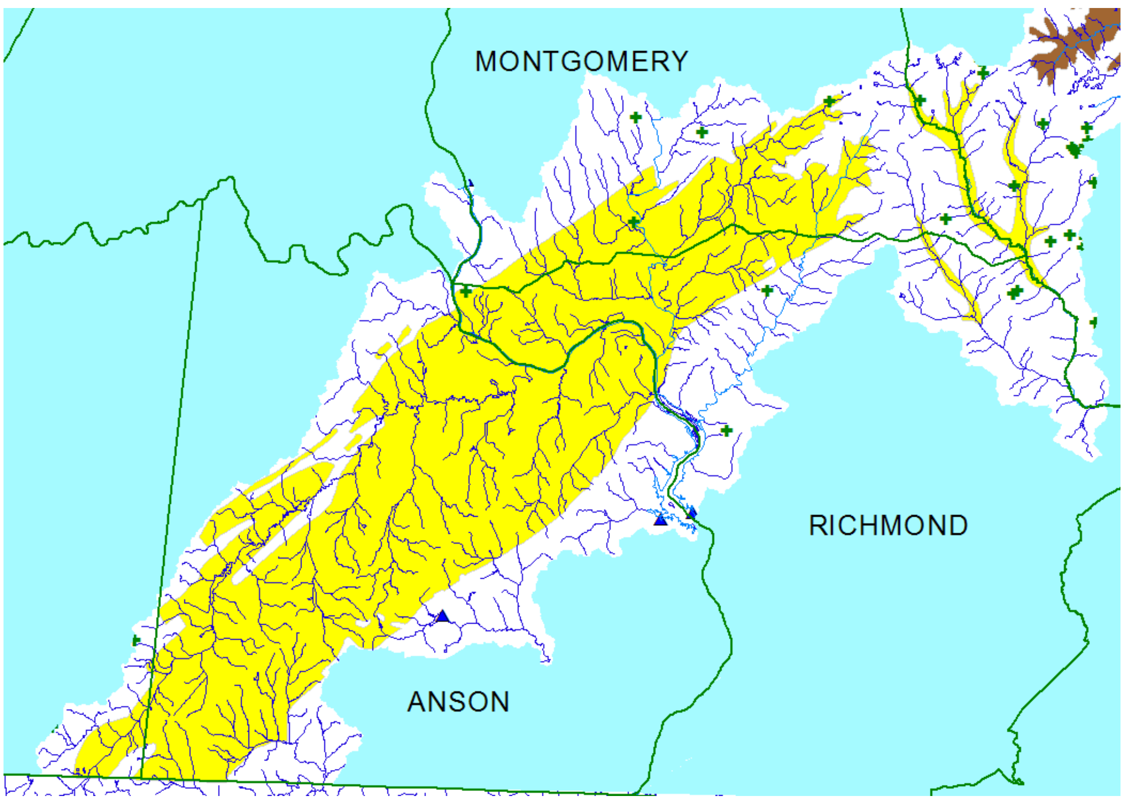


Table 3-7 shows the current population and the estimated population changes for the counties in this area based on North Carolina Office of State Budget and Management data. Seventeen

[23] Details on the communities supplied by the Anson County water system are available in their local water supply plan available on the Division of Water Resources' website at: http://www.ncwater.org/Water_Supply_Planning/Local_Water_Supply_Plan/

local government or large community water systems serve most of the residents of these counties. Estimates of current and future service populations for these systems are presented in Table 3-8 followed by estimated future water demand in Table 3-9.

Table 3-7. Wadesboro Triassic Sub-basin County Population

Wadesboro Sub-unit of Deep River Triassic formations			
County Population	Population	Population	Population
	2010	2020	2030
Anson County	26,973	27,454	27,941
Montgomery County	27,992	30,256	32,159
Richmond County	46,600	46,431	46,430
Total	101,565	104,141	106,530
(from OSBM website on January 6, 2012)			

Table 3-8. Wadesboro Triassic Sub-basin Local Water Supply Plan Service Population

Wadesboro Sub-unit of Deep River Triassic formations			
LWSP Service Population	Population	Population	Population
	2010	2020	2030
Anson County	26,183	26,561	26,918
Montgomery County	23,420	24,760	26,250
Richmond County	42,752	47,750	52,600
Total	92,355	99,071	105,768

Table 3-9. Wadesboro Triassic Sub-basin Local Water Supply Plan Water Use

Wadesboro Sub-unit of Deep River Triassic formations			
LWSP Service Area Demand	MGD	MGD	MGD
	2010	2020	2030
Anson County	4.253	4.67	4.602
Montgomery County	2.806	2.938	3.043
Richmond County	13.367	19.103	21.275
Total	20.426	26.711	28.92

County residents that are not supplied by a local government or large community water system depend on groundwater supplied by household wells or small community water systems. Table 3-10 calculates the number of residents dependent on private wells or well-based small community systems and estimates their daily average water needs, assuming that each person uses 75 gallons of water per day.

Table 3-10. Wadesboro Triassic Sub-basin Water Demands - Non-LWSP residents

Wadesboro Sub-unit of Deep River Triassic formations			
Non-LWSP Population/Demand			
Estimated @ 75 gals/person/day	2010	2020	2030
Anson County	790	893	1,023
Montgomery County	4,572	5,496	5,909
Richmond County	3,848	0	0
Total	9,210	6,389	6,932
Estimated water needs (mgd)	0.7	0.5	0.5
zero values indicate predicted service population exceeded predicted county population			

In addition to the registered water withdrawals and the estimated usage by individual households and small water systems, at least 44 agricultural operations in these counties each withdrew 10,000 gallons of water or more on at least one day during 2010. According to data from the annual survey of agricultural water users conducted by the Agricultural Statistics Division of the N.C. Department of Agriculture and Consumer Services[24] shown in Table 3-11, these facilities have the combined capacity to withdraw 31 million gallons per day from unspecified locations and sources in these counties. The lack of information on these and other unregistered water withdrawals makes it difficult to predict withdrawal needs and identify potential conflicts among water users.

Table 3-11. Wadesboro Sub-basin Agricultural Water Use

Wadesboro Sub-unit of Deep River Triassic formations				
2010 Daily Agricultural Use	Unique	Ave. Daily	Ave. Daily	Daily
Use in million gallons per day	Operations	Ground Water	Surface Water	Capacity
Anson County	9	0.073	*	2.103
Montgomery County	18	0.065	*	13.993
Richmond County	17	0.158	0.238	14.770
Total	44.0			30.9
Data from Dept. Agriculture & Consumer Services-Agricultural Statistics Division - Water Use Survey				
* data not released -one operation is greater than 60% of total or less than 3 operations				

Dan River Triassic Basin

The Dan River Triassic Basin is located along the southern boundary of the much larger hydrologically defined Upper Dan River sub-basin that encompasses 2,054 square miles in North Carolina and Virginia. The Dan River flows southeasterly from western Stokes County where it enters North Carolina. In the vicinity of the town of Walnut Cove, the river turns and begins flowing northeasterly, following the Triassic Basin and collecting the flows from the Mayo and Smith Rivers before flowing into Virginia in eastern Rockingham County. The study area is defined by 16 subwatersheds that overlay the Triassic Basin. In 2010, almost 75,000 persons resided in the more than 500 square miles of this study area, which includes 16 subwatersheds.

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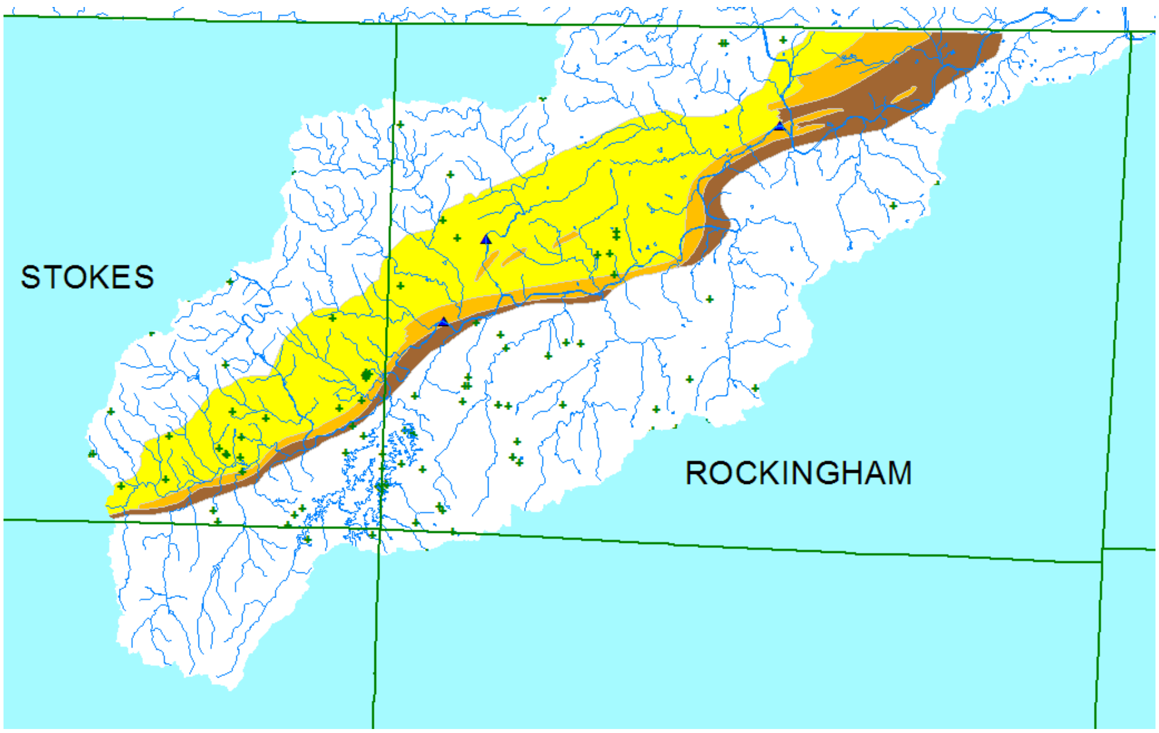
[24] The 2010 Agricultural Water Use Survey Report is available at: http://www.ncagr.gov/stats/environmental/WU2010.pdf

Six local government or large community water systems are found within this study area. Three of these systems withdraw surface water to supply their customers. Two of the remaining water systems purchase all of their water from one of the surface-water supplied systems. The sixth water system withdraws groundwater from seven wells within the Triassic Basin. Figure 3-5 shows the study area for the Dan River Triassic Basin with the geologic formations highlighted in yellow, orange and brown. The triangles in Figure 3-5 show the locations of the municipal surface water intakes and the crosses indicate the locations of community and non-community public water system wells.

Figure 3-5. Dan River Triassic Basin Study Area with Wells and Surface Water Intakes



The Dan River Triassic Basin in North Carolina lies within Stokes and Rockingham counties. Table 3-12 shows the estimated populations for Stokes and Rockingham counties according to the Office of State Budget and Management, including the changes expected through 2030. As shown in Table 3-13, the local government and large community water systems serve more than half of the residents in these counties and expect to increase that proportion over the next two decades. The growth in service population will be accompanied by increases in water demands. Table 3-14 shows the current and expected future water needs for these systems. Projections of future water demands are not available for water withdrawers or public water systems that do not prepare a local water supply plan.

Table 3-12. Dan River Triassic Basin - County Population

Dan River Triassic Formation			
County Population	Population	Population	Population
	2010	2020	2030
Rockingham County	93,764	98,664	103,563
Stokes County	47,478	49,802	51,033
Total	141,242	148,466	154,596
(from OSBM website on January 6, 2012)			

Table 3-13. Dan River Triassic Basin - Population Served by a Local Water Supply Plan Water System

Dan River Triassic Formation			
LWSP Service Population	Population	Population	Population
	2010	2020	2030
Rockingham County	51,441	53,407	55,699
Stokes County	22,395	26,735	31,890
Total	73,836	80,142	87,589

Table 3-14. Dan River Triassic Basin - Water Demands from Local Water Supply Plans

Dan River Triassic Formation			
LWSP Service Area Demand	MGD	MGD	MGD
	2010	2020	2030
Rockingham County	13.852	14.599	15.437
Stokes County	2.724	4.129	5.413
Total	16.576	18.728	20.85

County residents who are not supplied with water by a local government or large community water system will likely depend on local groundwater resources for their water supply. Some will receive water from a small well-based community water system; others will rely on individual household wells. Table 3-15 summarizes the number of residents in these categories and estimates current and future water needs. Each person is assumed to use 75 gallons of water per day. An undeterminable number of these residents will receive water from wells in the Triassic Basin, as do the current residents of the town of Walnut Cove.

Table 3-15. Dan River Triassic Basin - Population and Water Demands of County Residents Not Served by a LWSP System

Dan River Triassic Formation			
Non-LWSP Population/Demand			
Estimated @ 75 gals/person/day	2010	2020	2030
Rockingham County	42,323	45,257	47,864
Stokes County	25,083	23,067	19,143
Total	67,406	68,324	67,007
Estimated water needs (mgd)	5.1	5.1	5.0

Six registered water withdrawers are found in the study area: Aqua North Carolina (which operates two groundwater-based community water systems); two golf courses that withdraw water from ponds on golf course property; and the Dan River and Belews Creek steam stations operated by Duke Energy. The two steam stations use surface water to cool thermoelectric generation facilities. Data submitted to DWR indicate that more than 98 percent of the amount withdrawn by these facilities for electricity generation is returned to the source.

Table 3-16. Dan River Triassic Basin - Agricultural Water Use

Dan River Triassic Formation				
2010 Daily Agricultural Use	Unique	Ave. Daily	Ave. Daily	Daily
Use in million gallons per day	Operations	Ground Water	Surface Water	Capacity
Rockingham County	32	0.162	0.476	30.065
Stokes County	5	*	0.033	4.927
Total	37			35.0
Data from Dept. Agriculture & Consumer Services-Agricultural Statistics Division - Water Use Survey				
* data not released -one operation is greater than 60% of total or less than 3 operations				

In addition to the registered water withdrawals and estimated usage by individual households and small community systems, at least 37 agricultural operations in these counties each withdrew 10,000 gallons or more of water for at least one day during 2010 (see Table 3-16). According to the annual survey of agricultural water users conducted by the Agricultural Statistics Division of the N.C. Department of Agriculture and Consumer Services, these facilities have the combined capacity to withdraw 35 million gallons of water per day from unspecified locations within Stokes and Rockingham counties. The lack of information on these and other unregistered withdrawals makes it difficult to predict withdrawal needs and identify potential conflicts among water users.

Water availability

North Carolina has traditionally been considered a relatively water-rich state. This is still true at some times and in some areas. During some hydrologic conditions, however, water resources in some parts of the state strain to meet regional withdrawal and in-stream needs.

In general in North Carolina, water withdrawal permits are not required for water withdrawals.[25] However, there are certain actions that may require a permit from the state, such as the development of the infrastructure to treat and distribute large amounts of water. Depending on the location and scope of work, state-issued permits may be required in conjunction with federal permits needed to develop a proposed project. In free-flowing streams and rivers, proposed withdrawals associated with an action requiring a permit are evaluated by the permitting and commenting agencies based on the relationship between the amount of water to be withdrawn and the amount of water available during low-flow periods. The goal is

[25] The one exception is in the Central Coastal Plain Capacity Use Area, which does not intersect with the Triassic Basins. Also, parties wishing to use water from a hydropower project licensed by the Federal Energy Regulatory Commission must obtain permission from the licensee and from the FERC if the withdrawal is greater than one million gallons per day.

to identify the amount of water that can be withdrawn while still maintaining sufficient water in the stream to support aquatic life, ensure good water quality, and protect the rights of downstream landowners to also make beneficial use of the waters. To find this balance between a proposed withdrawal and other stream uses, low-flow conditions are characterized by the estimated 7Q10 flow in the vicinity of the withdrawal.

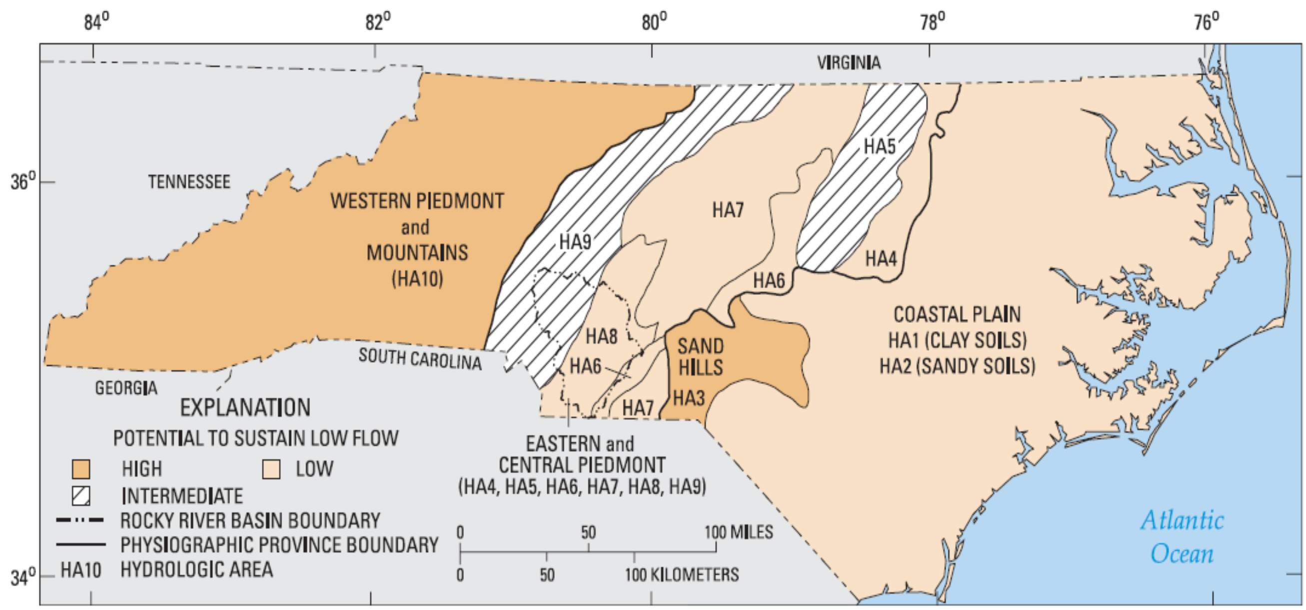
The 7Q10 flow is a statistical estimate, based on available flow records, of the lowest flows that would be expected to occur for seven continuous days once in 10 years. There is a 10 percent chance that this level of flows could occur in any particular year. Except for special situations such as trout streams, the rule-of-thumb for allowable individual or cumulative withdrawals from a stream or river, without requiring an in-depth environmental review, is that the instantaneous withdrawal be less than 20 percent of the 7Q10. This threshold is established under the N. C. Environmental Policy Act as one of several limits that define minimum criteria for construction activities in the evaluation of the level of environmental review required.[26] It is also cited in case of a dispute under the Right of Withdrawal of Impounded Waters Act as the presumed underlying flow that would be in a watercourse if the impoundment did not exist.[27] Proposed projects requiring instantaneous withdrawals greater than 20 percent of the 7Q10 may be acceptable if a site-specific in-stream flow study indicates the desired level of withdrawal will maintain sufficient water to support aquatic life, ensure good water quality and protect the rights of other users. New withdrawals may be possible from existing reservoirs, however access to water from a legally constructed surface water impoundment is controlled by the owner of the impoundment.[28]

The USGS conducts Water-Resources Investigations using nationally standardized methodologies that evaluate low-flow characteristics of river basins in North Carolina. Several of these studies provide useful information to describe low-flow conditions in the vicinity of the Triassic Basins.[29] Low-flow conditions, frequently referred to as base flow, occur during extended periods of time between rainfall events and represent the level of surface water flow that can be supported by groundwater discharges into the surface water channel. Groundwater discharges are influenced by a variety of geologic characteristics including typography and aquifer composition. The rock and sediment composition of the Triassic Basins are noted for having a limited ability to transmit water, and therefore areas in the Triassic Basin typically exhibit very low base flow conditions.

[26] 15A N.C.A.C. 01C .0408 (2)(b)(i)
[27] General Statute § 143-215.44(a)
[28] General Statute § 143-215.44 et.seq. Right of Withdrawal of Impounded Waters
[29] Weaver, J. C. “Low-flow Characteristics and Profiles for Selected Streams in the Roanoke River Basin, North Carolina: U.S. Geological Survey Water-Resources Investigations Report 96-4154.” USGS, 1996.
Weaver, J. C. “Low-Flow Characteristics and Profiles for the Deep River in the Cape Fear River Basin, North Carolina: U.S. Geological Survey Water-Resources Investigations Report 97-4128.” USGS, 1997.
Weaver, J. C., and B.F. Pope. “Low-flow Characteristics and Discharge Profiles for Selected Streams in the Cape Fear River Basin, North Carolina, through 1998: U.S. Geological Survey Water-Resources Investigations Report 01-4094.” USGS, 2001.

The USGS publication "Low-Flow Characteristics of Streams in North Carolina"[30] provides some general guidelines for estimating low-flow values for hydrologically grouped areas in the state. The authors sub-divided the state into 10 distinct hydrologic areas based on available base flow data and published a set of coefficients to allow estimation of several low-flow statistics based on the square miles of drainage area contributing runoff to a point of interest. They include estimates of the drainage area likely to be needed to produce a 7Q10 flow estimate greater than zero. Data from this report were used to estimate the potential ranges of low-flows that could occur in parts of the two study areas. These estimates provide guidance as to the possible magnitudes of surface water withdrawals possible under the presumption that 20 percent of the 7Q10 flow would be available without site-specific environmental evaluations. Figure 3-6 shows the delineations of the hydrologic areas established for North Carolina.

Figure 3-6. Hydrologic Areas of Similar Potential to Sustain Low Flows in North Carolina



Study areas were defined by the sets of subwatersheds encompassing the Deep River Triassic Basin and the Dan River Triassic Basin. The study areas are shown in Figure 3-7 with the units of the Triassic Basins highlighted in yellow, orange, and brown. Figure 3-8 and Figure 3-9 show more detailed views of the study areas, showing the boundaries of the hydrologic areas relevant for each of the sub-basins of the Deep River Triassic Basin.

[30] Giese, G.L., and R.R. Mason, Jr. "Low-flow characteristics of streams in North Carolina: U.S. Geological Survey Water-Supply Paper 2403." USGS, 1993.

Figure 3-7. Sanford Triassic Sub-basin Study Area

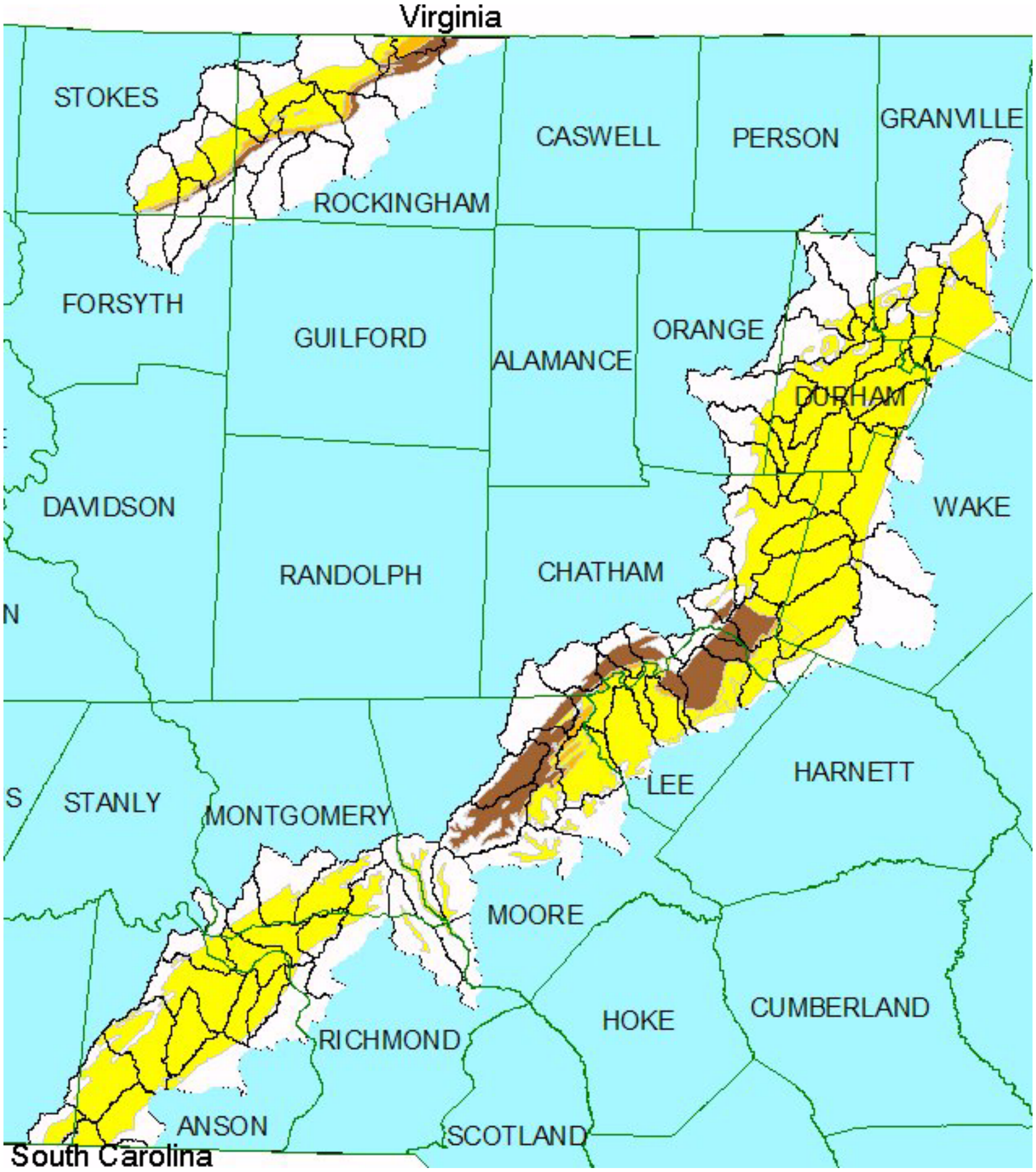
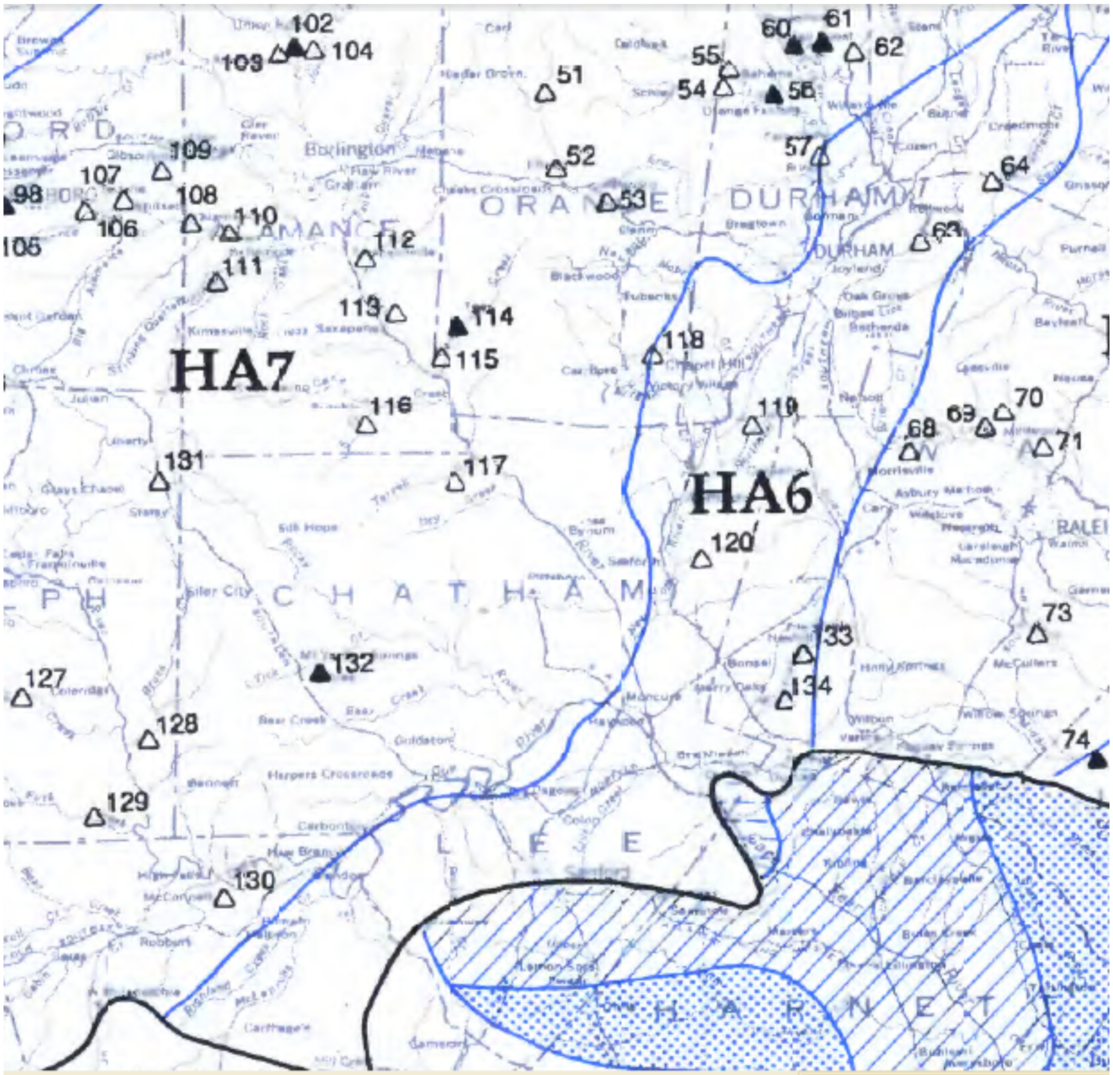


Figure 3-8. Hydrologic Areas – Sanford and Durham Sub-basins of Deep River Triassic Basin



The study area for the Sanford and Durham Triassic Sub-basins is defined by a group of subwatersheds that fall within Hydrologic Area 6 (Triassic Basin) and Hydrologic Area 7 (Carolina Slate Belt). The USGS report estimates the range of 7Q10 flows for drainage areas designated as HA6 between zero and 0.004 cubic feet per second (cfs) per square mile; with the additional caveat that 7Q10 flows greater than zero would only be likely in drainage areas greater than 45 square miles. The range of values for drainage areas designated as HA7 is from zero to 0.131 cfs per square mile with the likelihood of seeing 7Q10 flows greater than zero from drainage areas as small as three square miles. Given these parameters, the range of 7Q10 flows from a hypothetical 60 square mile drainage area could be from zero to 0.024 cfs in the HA6 areas and from zero to 7.86 cfs in the HA7 areas.

The Deep River flows through the northern part of the Sanford Triassic sub-basin carrying water collected from more than 1,434 square miles of drainage area and sustained by minimum releases from several reservoirs upstream of the study area. The 7Q10 flow at the USGS stream gage in Moncure near the mouth of the river has been estimated by USGS at 24 cfs. The area upstream of the Triassic Basins contributes most of this flow. For example, above the confluence with Bear Creek a drainage area of 621 square miles produced an estimated 7Q10 flow in the Deep River of 18 cfs.[31] The remaining 813 square miles of drainage between Bear Creek and Moncure only contributes 6 cfs out of the total 7Q10 flow of 24 cfs at Moncure.

At the northern limit of the Sanford Triassic Sub-basin, the dominant water source is the Cape Fear River. Water from the Haw River flows through Jordan Lake, a reservoir operated by the U.S. Army Corps of Engineers, and joins with water from the Deep River to form the Cape Fear River. Almost all of the water flowing over the Triassic Basin in the Cape Fear River originates to the north of the geologic basin in the Deep River and Haw River drainage areas. Flows in the Cape Fear River are augmented by releases from Jordan Lake with a goal of maintaining flows of 600 cubic feet per second in the river at the Lillington stream gage. These releases are made to maintain artificially higher low flows in the river for water quality purposes, which also reduces the uncertainty of water availability for downstream water withdrawers. The city of Sanford withdraws water several miles downstream of the confluence of the Deep and Haw rivers, above the Lillington stream gage. Sanford's 2010 local water supply plan indicates they have 12.6 million gallons per day available at the intake location and the city uses between 5.5 and 9 mgd.

In the Durham Triassic sub-basin surface water availability is dominated by Jordan Lake and Falls Lake. The water supply storage in Jordan Lake is estimated to be able to supply 100 mgd. Allocations of water supply storage are made by the Environmental Management Commission to units of local government based on demonstrated need. Currently 63 percent of the storage is allocated to eight entities.[32] Water supply storage in Falls Lake is reserved for the city of Raleigh.

While proximity to the Deep or the Cape Fear River may increase the reliability of surface water supplies and provide access for larger water withdrawals, oil and gas projects not in the immediate vicinity of these sources will face more uncertainty with regards to surface water availability in the tributary subwatersheds. The smaller drainage areas of tributary streams produce more variable flow conditions and lower low-flow conditions. The volume of water that can be withdrawn without degrading water quality or affecting other users may not be enough to support gas well development.[33]

Also, consideration has to be given to the potential water use conflicts that could arise during drought conditions. If drilling operations and intermittent agricultural users decide to withdraw water at the same time, neither may be able to get the volume of water desired. Without a

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[31] Weaver, J.C. "Low-Flow Characteristics and Profiles for the Deep River in the Cape Fear River Basin, North Carolina: U.S. Geological Survey Water-Resources Investigations Report 97-4128." USGS, 1997.

[32] Details on current allocations and the allocation process are available on the DWR website at: http://www.ncwater.org/Permits_and_Registration/Jordan_Lake_Water_Supply_Allocation/

[33] In areas where withdrawals greater than two million gallons per day are possible, state law on interbasin transfers may apply if the water will be withdrawn from one river basin and used in another. Familiarity with the interbasin transfer basin boundaries map could avoid delays in accessing productive water sources.

regulatory regime that clearly defines allowable withdrawals, resolution of the conflicts must be reached by negotiated agreements between the parties or in the courts.

Except in the Central Coastal Plain Capacity Use Area, water withdrawal permits are not required to extract groundwater under an individual's property. In general, wells in the Triassic Basins are not prolific. Depending on the subsurface formations, well yields vary considerably. Table 18 at the end of this section presents yield estimates for public water supply wells located in the Triassic Basins evaluated in this analysis. Proximity to fractures in the underlying rock or vertical intrusions that can aid in the vertical movement of water between horizontal rock layers are critical factors in determining well yield. For example, one small community water system in Lee County is supplied by three wells in the Triassic Basin that have yields of five, 25 and 76 gallons per minute.

As an alternative to operating independent water withdrawals, new projects may choose to get water from existing local government water systems. Local water utilities with unused capacity may welcome the opportunity to sell water, on a time-limited basis, to drilling operations within or bordering the footprints of their distribution systems.

The Wadesboro Triassic sub-basin lies with the USGS-designated Hydrologic Areas HA6 and HA7, like the Sanford and Durham Triassic sub-basins. Therefore estimates of potential low-flows in the area would be similar to those discussed earlier. As noted in the description of this area, the Triassic Basin is transected by the Pee-Dee River in which flows are regulated by hydroelectric power operations and federal license requirements. The county water systems withdraw water from Lake Tillery and Blewett Falls Lake and distribute drinking water throughout major portions of the Wadesboro Triassic sub-basin.

Figure 3-9. Hydrologic Areas - Wadesboro Sub-unit

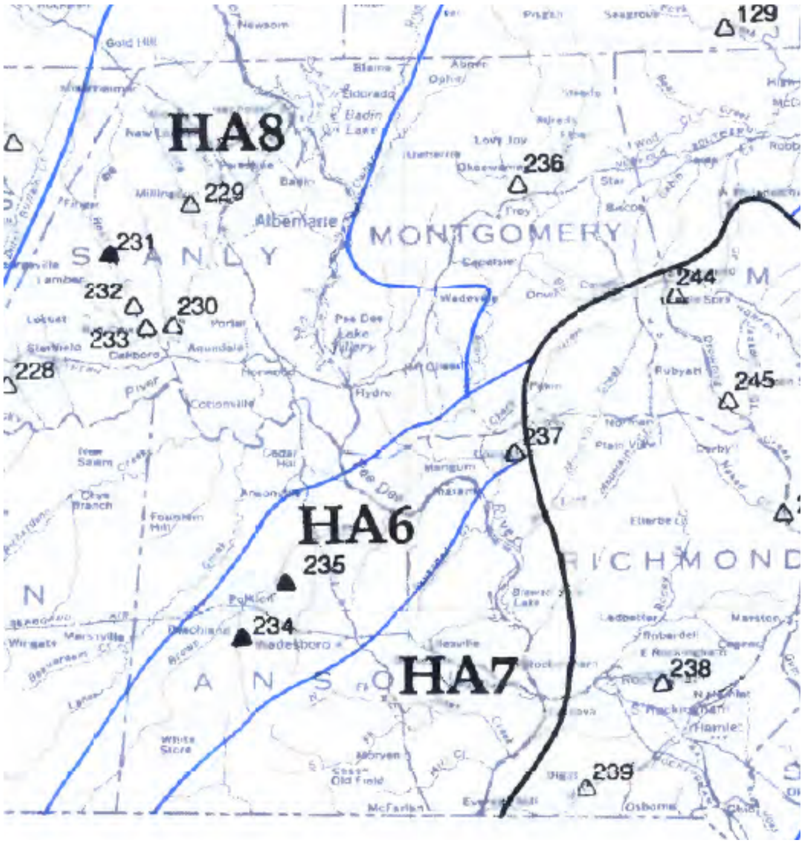

Figure 3-10. Dan River Triassic Basins Study Area

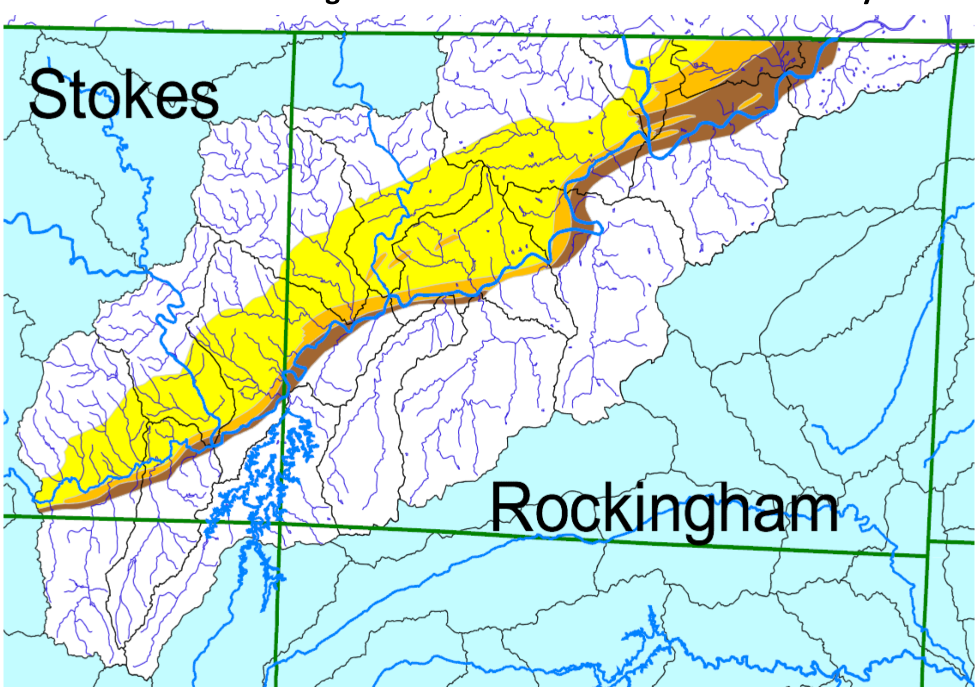

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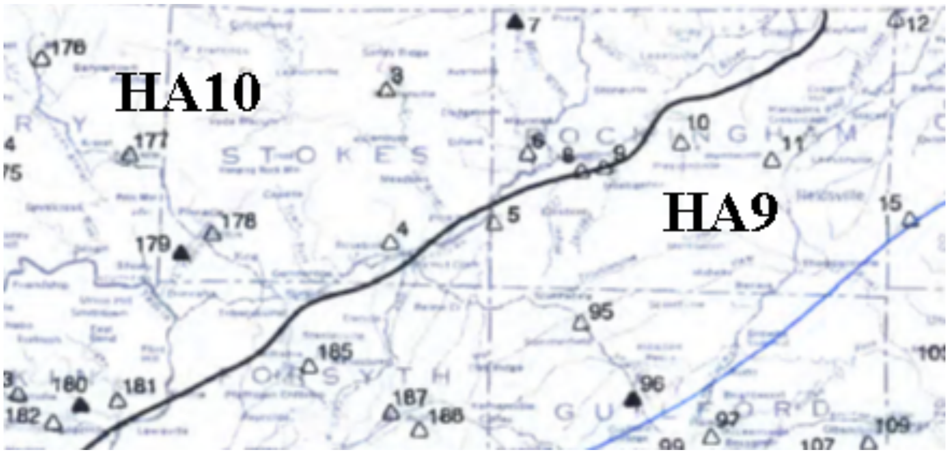
Figure 3-11. Hydrologic Areas - Dan River Triassic Basins



The Dan River Triassic Basin study area is defined by 16 hydrologic subwatersheds. The drainage areas south of the Dan River are designated as Hydrologic Area HA9 (Charlotte Belt and Milton Belt) and areas north of the river are designated as HA10 (Western Piedmont and mountains). Estimates for 7Q10 flows for the HA9 areas range from zero to 0.16 cfs per square mile with drainage areas larger than one square mile likely to produce 7Q10 flow estimates greater than zero. Estimated low flows for the HA10 are predicted to vary from zero to 1.062 cfs per square mile with 7Q10 flows greater than zero likely from drainages larger than half of a square mile. Using these parameters a hypothetical 60 square mile drainage area in the HA9 area may produce 7Q10 flows from zero to 2.67 cfs and from zero to 63.72 cfs in the HA10 area.

The Dan River Triassic Basin lies along the lower boundary of the Upper Dan River hydrologic sub-basin. The majority of the sub-basin drainage area lies north of the river where the geologic formations support higher baseflow conditions. The Dan River near Pine Hall, N.C., before its confluence with the Mayo or Smith Rivers, has an estimated 7Q10 flow of 80 cfs. After its merger with the Mayo River, the 7Q10 flow near Wentworth increases to 175 cfs. The Smith River joins the Dan River further downstream. Flows in the Smith River are influenced by releases from Philpott Reservoir upstream in Virginia. After merging with the Smith River, the 7Q10 estimate for the Dan River increases to 375 cfs. Within the study area, the major tributaries of the Dan River flow southerly, transecting the Triassic Basin, before merging with the main river channel that parallels the Triassic formation close to its southern boundary. The ability of the geologic formations in the areas north of the Triassic Basins to support relatively high low-flow conditions reduces the uncertainty associated with using streams in these areas as water sources for gas well development.

The town of Walnut Cove relies on seven wells drilled in the Dan River Triassic Basin in Stokes County. The wells range in depth from 130 to 1,230 feet and reported yields for the various wells range from 35 to 140 gallons per minute. In Rockingham County, public water systems with wells in the Triassic Basins produce yields of six to 22 gallons per minute. As noted earlier, groundwater availability in the Triassic Basins varies considerably, which limits the ability to accurately estimate well yields prior to well completion. The amount of water available to wells drilled in the Triassic Basins is influenced by the nature of fractures occurring in the source rock in the vicinity of the well. Given the highly variable nature of fracture networks, it will be difficult to predict impacts to neighboring wells before pumping of the new wells actually begins.

Under current state law, a property owner can make reasonable use of the groundwater under the property. If a well used to supply water for hydraulic fracturing is located on the same property as a drinking water well, the owner of the drinking water well would have little or no ability to recover damages for loss of water supply because of the increased pumping. The driller's use of the groundwater would be assumed to be reasonable.

As in the vicinity of the Sanford Triassic Basins, the possibility of accessing the unused capacity of existing community water systems may provide a reasonable option for projects in this area. Several municipal water utilities that currently produce and distribute treated surface water to customers in the study area.

Existing regulatory structure for water withdrawals for shale gas exploration and production

Outside the 15-county Central Coastal Plain Capacity Use Area (which does not overlap the Triassic Basin), North Carolina law does not currently require a water withdrawal permit for either surface or groundwater withdrawals. North Carolina may be one of only a handful of states (perhaps as few as two to four) without a statewide water withdrawal permitting requirement.[34] Most of the major oil and gas producing states require permits for large water withdrawals.

The ability to put conditions on a proposed water withdrawal associated with hydraulic fracturing will be dependent on the operator's need for a permit that would trigger a review of those impacts. The developer of an oil or gas well must apply for a drilling permit from the Division of Land Resources, but the permit review required under the state Oil and Gas Conservation Act does not appear to cover off-site water withdrawals and construction of water storage structures.[35]

It is unclear that DENR has the authority to place conditions on a drilling permit to limit surface water withdrawals. Currently, DENR reviews the impact of a proposed water withdrawal only if the withdrawal is associated with infrastructure (such as a water treatment plant) or in-stream activities (such as construction of an impoundment or in-stream water intake structure) that would trigger a broader permit review. Public infrastructure projects involving large water withdrawals often require an environmental assessment or environmental impact statement (EIS) under the state Environmental Policy Act (SEPA), G.S. 113A-1, et seq. In those cases, the SEPA document addresses all project impacts, including the surface or groundwater withdrawal. Since SEPA only applies to projects that involve the expenditure of public funds or the use of public lands, however, SEPA review would not be required for a water withdrawal associated with commercial natural gas production unless public funds – such as an economic incentive grant – were involved.

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[34] Email from Richard Whisnant, UNC School of Government.

[35] N.C.G.S. 113-396; 15A NCAC 05D .0105

Some types of water intake structures and other activities associated with surface water withdrawals may require a permit from the U.S. Army Corps of Engineers under either Section 404 of the federal Clean Water Act[36] (for deposition of fill material in waters and wetlands) or under Section 10 of the Rivers and Harbors Act of 1899 (for structures in navigable waters). If a Section 404 permit is required, the project would also need a certification from DENR's Division of Water Quality that the project would be consistent with state water quality standards.[37] This certification, called a Section 401 Certification (referring to the Clean Water Act section) can look broadly at water quality impacts. It is possible to use the Section 401 Certification to review the water quality impacts of a large individual withdrawal; the water quality certification does not, however, provide a good tool for protecting other water users who may be affected by the volume of a new withdrawal.

These environmental reviews will only occur if the method used to withdraw water involves deposition of fill material, disturbance of the stream bottom, placement of a structure in navigable waters or some other activity that would require a permit. Use of a simple in-stream pump may not require review under either federal or state law. When large scale hydraulic fracturing for natural gas began in Pennsylvania in 2005, that state's rules did not require any permit for the associated water withdrawals. Some streams went completely dry for a time because the industry withdrew large amounts of water over a very short period of time during low flow periods.[38] As a result of those problems, the Pennsylvania Bureau of Oil and Gas Management amended its rules in 2008 to require operators to submit a water management plan. In reviewing those plans, the Pennsylvania agency applies water withdrawal guidance developed by the Susquehanna River Basin Commission. These regulatory changes caused the industry to alter its water withdrawal practices; operators now stockpile water for hydraulic fracturing over a period of time, stored in impoundments near the drilling site, to avoid extreme impacts on stream flows.

Because of highly variable yields from wells in the Triassic Basins, groundwater would be a less reliable source of water for hydraulic fracturing than surface water. While many areas in the Triassic Basins have surface water sources capable of providing adequate water supply there are many other areas where nearby streams do not have enough water to supply well development needs while protecting water quality and the rights of other users. In some areas, the groundwater most often used for drinking water supplies has limited yield and may not be adequate to quickly generate the volumes required for fracturing. Without the ability to condition a permit for drilling oil or gas wells, the source of water for hydraulic fracturing would not be subject to review to maintain sufficient water in streams to support aquatic life, ensure good quality water and protect the rights of other landowners to also make beneficial use of the waters. Under current state law, a new well used to supply water for drilling operations would be treated as a private water supply well and only required to meet well construction

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[36] 33 U.S.C. § 1344 (2010)
[37] 33 U.S.C. §1341 (2010)
[38] WTAE. "Pa. Streams Drained Dry by Drillers." November 17, 2008. Retrieved March 6, 2012 from http://www.wtae.com/r/17973811/detail.html.

standards. No review of the potential impact of the well(s) on other public or private water supply wells, groundwater levels or stream flow would take place.

In short, it is unclear that DENR has sufficient authority to limit or manage the timing of water withdrawals in connection with hydraulic fracturing. If there are no permit limitations on water withdrawals, the proximity of the water source and transportation constraints (such as whether the water is piped or trucked to the well pad) will likely determine the timing and magnitude of withdrawals. As noted in the New York Draft Generic Environmental Impact Statement,

> "Without proper controls on the rate, timing and location of such withdrawals, modifications to groundwater levels, surface water levels, and stream flow could result in adverse impacts to aquatic ecosystems, downstream flow levels, drinking water assured yields, wetlands, and aquifer recharge."[39]

Some of the states with active shale gas extraction activities have regulatory systems in place to monitor groundwater and surface water withdrawals for hydraulic fracturing. In Pennsylvania and New York, the Delaware River Basin Commission (DRBC) and the Susquehanna River Basin Commission (SRBC) use a permit system and approval process to regulate existing water usage. Operators must provide a comprehensive project description, including site location, water source(s), location of withdrawals, proposed timing and rate of water withdrawal and the anticipated project duration. In addition, operators must identify the amount of consumptive use and any import or export of water to or from the hydrologic basin. Once the project is approved, operators must meter withdrawals and submit quarterly reports to the DRBC or the SRBC.[40]

The Pennsylvania Department of Environmental Protection (DEP) has similar requirements for the areas of the state outside the Delaware and Susquehanna River Basins. The 2002 Water Resources Planning Act requires entities withdrawing more than 300,000 gallons of water over a 30-day period to register their water withdrawal. Thus DEP now monitors water withdrawals outside the commissions' basins. In 2008, the Pennsylvania Bureau of Oil and Gas Management began requiring water management plans to identify water withdrawal locations and volumes. This process was established to allow DEP to assure that excessive withdrawals do not occur. DEP follows guidance from the SRBC.[41]

In New York, the Water Resources Law extends the Department of Environmental Conservation's authority to regulate all water withdrawals of more than 100,000 gallons per day throughout the state of New York. The law applies to water used for hydraulic fracturing. The New York Draft Generic Environmental Impact Statement states that future withdrawal permits issued pursuant to the regulations implementing the Water Resources Law "would include conditions to allow the Department to monitor and enforce water quality and quantity standards, and requirements." NYSDEC is currently developing these regulations, but notes that the requirements may include "passby flow; fish impingement and entrainment protections;

[39] NYSDEC, p. 6.2.
[40] NYSDEC, p. 6-8.
[41] STRONGER. *Pennsylvania Hydraulic Fracturing State Review*. September 2010. Retrieved March 4, 2012 from http://www.shalegas.energy.gov/resources/071311_stronger_pa_hf_review.pdf.

protections for aquatic life; reasonable use; water conservation practices; and evaluation of cumulative impacts on other water withdrawals."[42]

Since North Carolina does not have a permitting system for water withdrawals, no clear tool exists for monitoring the location, volume or rate of water withdrawals for hydraulic fracturing. Without the ability to manage the volume and timing of those withdrawals, North Carolina could experience adverse impacts on water resources and on other water users.

Estimated water needs for gas well development

To estimate potential water needs for gas well drilling and hydraulic fracturing, a set of assumptions were developed to capture the range of possible water needs. The assumptions were based on information about water use options employed in other natural gas exploration areas, discussions with industry representatives, and the best professional judgment of DENR staff.

Many variables influence the amount of water that will actually be needed to drill and develop gas extraction wells in North Carolina. To develop a plausible estimate of an upper limit on water use, the scenarios used for this analysis do not consider the potential withdrawal reductions that could be realized by recycling water within drilling operations. The ability to recycle used water may not exist until after the potential for gas production has been determined and several wells have been hydraulically fractured, making it practical to invest in a recycling operation. If gas well development becomes a reality in North Carolina then water management practices implemented to control costs may reduce water usage below the estimates presented in this analysis.[43]

Industry Terms

Produced water: A naturally occurring by-product of natural gas and oil extraction that travels from the producing formation through the wellbore to the surface with natural gas and oil during completion and production operations.. Produced water generally contains various salts, sand, silt and naturally occurring radioactive materials (NORM).

Flowback water: The mixture of hydraulic fracturing fluids, proppant, and produced water that flows up through the wellbore to the surface after hydraulic fracturing is completed and the direction of fluid flow reverses.

Flowback: The process of flowback water returning up the wellbore to the surface.

Based on available information from other parts of the country, total water use for each successful production well, including hydraulic fracturing, is likely to be between three and five million gallons. In comparison to other water users, the total amount of water needed for hydraulic fracturing of natural gas wells is a modest amount. There are many communities across the state that use an average of five million

[42] NYSDEC, p. 6-8.
[43] The New York State Department of Environmental Conservation reports that in Pennsylvania, "Current practice is to use 80% - 90% fresh water and 10% - 20% recycled flowback water for high-volume hydraulic fracturing." NYSDEC, p. 6-10.

gallons of water per day and more throughout each year. Based on information from the 2010 local water supply plans, five million gallons is approximately the volume of water that communities like Lenoir, Lincolnton, Monroe, Roxboro, Spruce Pine, and Statesville use on average daily basis to meet their customers' water demands. Slightly larger communities like Burlington, Hickory, and High Point used over twice that amount on a daily average basis in 2010. Of the 552 water systems that submitted a local water supply plan for 2010, 47 systems used five million gallons per day or more on average, 341 used 0.25 mgd or more on average, and 391 use 0.145 mgd or more on average to meet their customers' demands.

A variable percentage of the water used for hydraulic fracturing is recovered shortly after the process is finished. This recovered water is called flowback. The volume of flowback reported in the Marcellus shale in northern Pennsylvania ranges from 9 to 35% of the fluid pumped into a well for hydraulic fracturing.[44] Most of the water used in the hydraulic fracturing operation remains trapped in the geologic formations. In some cases flowback can be mixed with water from other sources and additional hydraulic fracturing additives to reduce the quantity of new water needed for hydraulic fracturing of subsequent nearby wells.

Hydraulic fracturing is undertaken after a well has been drilled. By this point in the process activities at the drilling site have been ongoing for some time. A site had to be chosen, permits acquired, well pad prepared, equipment moved into place, and the well drilled. The time needed for these activities will vary but is assumed to require 38 to 56 days.[45]

In other states drilling operations often accumulate the necessary volume of water over a period of time and store the water either onsite or at a surface water impoundment within close proximity so it is available when needed. The time needed to accumulate the desired volume of water depends on permit withdrawal limits, water source compatibility, proximity to the well site, and transport requirements. Water is either moved by overland pipe or truck directly from the source water to the well pad, or it is piped from the source water to the surface water impoundment. From the surface water impoundment, the water is either piped or trucked to the well pad.

The magnitude, timing and source of water withdrawals is strongly influenced by laws regulating water withdrawals. Most oil- and gas-producing states have water withdrawal permitting requirements; many are relatively water-poor western states that have long regulated withdrawals. If the state permit does not include withdrawal restrictions, the timing and rate of withdrawal is completely up to the operator. Under current North Carolina law, the Division of Land Resources does not have the authority to regulate water withdrawals as a condition of a drilling permit. Since North Carolina does not have a statewide water withdrawal permitting system, withdrawal decisions would generally be up to the operator.

[44] NYSDEC, p. 5-99.
[45] NYSDEC, p. 6-298.

It is technically feasible for an operator to withdraw three to five million gallons of water within a two to four day pumping period. [46] To address this possibility, DENR's analysis includes a scenario involving water withdrawals made within a three-day pumping period. An average of one million gallons per day could be pumped over three days to supply three million gallons to a well site. If the goal was to accumulate five million gallons, then daily withdrawals would average 1.667 million gallons.

The American Petroleum Institute encourages contractors undertaking hydraulic fracturing operations to coordinate water withdrawals to minimize effects on aquatic life and other users, especially public water systems. However, the API guidance is not mandatory. The language of the guidance document implies that each state will impose limitations on drilling operations to protect resources the state chooses to protect.[47]

In states where water withdrawals are regulated through the drilling permit or a separate water withdrawal permit, operators may pump smaller amounts for a period of days or weeks to accumulate the amount needed to fracture. DENR has analyzed two alternative scenarios for water withdrawal: 1. Pumping the necessary amount over a three-day period; and 2. Pumping the necessary amount over a period of three weeks (21 days). If the operator pumps water over a period of 21 days to accumulate water onsite for fracturing, then withdrawals of about 143,000 gallons (0.22 cubic feet per second) per day would be adequate to accumulate three million gallons. If five million gallons of water were needed, then daily withdrawals of about 238,000 gallons (0.37 cubic feet per second) per day over a period of 21 days would be adequate. Longer withdrawal times that allow smaller daily withdrawals may also make it possible to use smaller water sources.

From the perspective of water resource management and the potential impacts to water resources and other water users, the total volume of water needed is less critical than the withdrawal rate and the timing of water withdrawals. Stream flows vary throughout the year and withdrawals made when flows are low would have more impacts on aquatic habitats, water quality and downstream users than the same level of withdrawal made when flows are higher. Taking 1.667 mgd of water from a stream for three days would have different impacts than withdrawing 0.5 mgd from the same location for 10 days or 0.25 mgd for 20 days. Each approach would withdraw five million gallons in total.

Being able to get the water needed by withdrawing smaller volumes over a longer period of time provides the ability to get water from more locations while maintaining sufficient water to support aquatic life, ensure good water quality, and protect the rights of landowners to also make beneficial use of the waters. The state has more water sources capable of supporting a 0.24 mgd (0.37 cfs) withdrawal than water sources capable of supporting a 1.667 mgd (2.58 cfs)

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[46] The two to four day estimate for total withdrawal time was provided in a phone conversation with DENR staff by David Miller of the American Petroleum Institute. This number is based on the use of a typical centrifugal pump. The time needed to withdraw this water depends on permit requirements, stream flow, and equipment.

[47] American Petroleum Institute; 2010; API Guidance Document HF2-Water Management Associated with Hydraulic Fracturing. http://www.api.org/oil-and-natural-gas-overview/exploration-and-production/hydraulic-fracturing/api_hf2_water_management.aspx

withdrawal. However, without the authority to regulate the location, timing and magnitude of withdrawals, the potential exists for withdrawals supporting gas exploration to reduce stream flows to levels that would produce unrecoverable ecosystem impacts or limit water available for other landowners' beneficial uses.

Overall, water usage will also be influenced by the number of gas wells that are developed. Since we do not know how much production will occur in North Carolina, DENR estimated the number of wells that could be developed in the Deep River and Dan River Triassic Basins. Not all formations of the Triassic Basins show the potential to produce hydrocarbons in the form of natural gas. Because of its lack of potential to produce hydrocarbons, the areas of the Pekin Formation in the Deep River Triassic Basin were subtracted from the total area of the Triassic Basins to arrive at a working estimate of about 785,000 acres of potential area for gas well development.

Consistent with other sections of this report, the analysis presented here assumes a well spacing of one well on 160 acres. North Carolina law does not currently address well spacing; 160 per well is used in several other states. Given the working estimate of 785,000 acres available for development with a spacing of 160 acres per well the maximum number of wells possible would be 4,904. If the state chose a different well spacing unit (such as one well on 60 acres), the number of potential wells and the amount of water required would increase proportionately.

Complete development of the gas production potential of North Carolina's Triassic Basins would happen over an indeterminate time span. In other parts of the country, shale plays are in the middle of production and it is unknown how long those areas will remain productive. Some estimate that shale gas plays will last 20 to 40 years. If well development were evenly distributed over 30 years in North Carolina, then 164 wells could be drilled each year across both Triassic Basins (at 160 acres per well).

For this analysis the actual drilling, hydraulic fracturing, and completion of a well was assumed to take three months. This results in an estimated 41 wells being developed within each three-month period.

At five million gallons per well and a three-day pumping time, 68 million gallons per day would be withdrawn to supply 41 wells. For the same number of wells, daily withdrawals would drop to 10 million gallons per day if the water was pumped and stored over a 21-day period. At three million gallons per well, pumping rates range from 41 million gallons per day over three days to six million gallons per day over 21 days.

Assuming that all the 785,000 acres will actually be able to produce recoverable natural gas is likely too optimistic. Gas operators may not be able to obtain leases for all areas within the Triassic Basins, particularly in urban areas where parcel sizes are small and agreements have to be negotiated with multiple parties to assemble leases covering sufficient contiguous acreage to allow drilling. In addition, not all areas within the Triassic Basins may be suitable for drilling.

Assuming only half of the estimated maximum number of wells are installed over the same 30-year time horizon reduces the number of wells drilled annually to between 82 and 218, depending on spacing. The amount of water needed for each well may not change but the total withdrawals needed to support this level of gas well development would likely decrease by half. Similarly if only one quarter of the estimated maximum numbers of wells were developed total water withdrawals for each pumping day would be reduced by about three quarters from the estimates above. The details of these alternative scenarios are summarized in Table 3-17.

Table 3-17. Analysis Scenario Descriptions

Assumptions				
Well spacing (acres per well)	160	160	160	160
Pumping Days	3	21	3	21
Water per well (million gallons)	3	3	5	5
Development cycles per year	4	4	4	4
Years of development	30	30	30	30
Triassic Basins' estimated acreage	785,000	785,000	785,000	785,000
Estimations				
Maximum number of wells for spacing	4,906	4,906	4,906	4,906
Wells per year if maximum number	164	164	164	164
Wells per quarter if maximum number	41	41	41	41
Water per well per pumping day (mgd)	1.000	0.143	1.667	0
Total water per pumping day (mgd)	41	6	68	10
Total water per pumping day @ 50% development (mgd)	20	3	34	5
Total water per pumping day @ 25% development (mgd)	10	1	17	2
Water per well per pumping day (cfs)	1.547	0.221	2.579	0.368
mgd = million gallons per day cfs = cubic feet per second				

This analysis presents one set of potential scenarios using assumptions based on experiences in other gas producing areas of the country. By focusing on withdrawing water over a three-day period this analysis estimates the upper limits of the volumes of water that could be withdrawn daily. Analyzing withdrawals over a period of 21 days describes a lower limit of withdrawals that could supply the volumes of water needed to support gas well development. These approaches also provide valuable information for identifying water sources that could be used to supply water. If a particular drilling site is located near a watercourse with flows that could only support withdrawals of 0.24 mgd (0.37 cfs) then with careful planning it may still be possible to accumulate five million gallons for gas well development. This example implies the ability to regulate the location, timing and magnitude of surface water withdrawals to maintain sufficient water in the source to support aquatic life, ensure good water quality, and protect the rights of downstream landowners to also make beneficial use of the waters.

Without the authority to regulate water withdrawals, critical decisions on location, timing and pumping rates would depend on the independent decisions made by the well development operators. The choice to withdraw five million gallons of water over 21 days at an environmentally protective rate of 0.24 mgd (0.37 cfs), or to make the withdrawals over three days at a technically possible rate of 1.67 mgd or 2.6 cfs, would be solely up to the contractor.

For instance, the Simpson #1 gas well, which is currently shut-in, is in the Pocket Creek subwatershed in Lee County. Pocket Creek is the closest free flowing perennial stream. There are 24,090 acres or about 37.6 square miles in this subwatershed located in the USGS designated Hydrologic Area HA6. The USGS guidance[48] suggests a maximum estimate of the 7Q10 flow in a subwatershed of this size in an area designated as HA6 would be about 0.15 cfs based on 0.004 cfs per square mile. However, the USGS includes an additional caveat for this category that a drainage area of 45 square miles would likely be needed to produce a 7Q10 flow greater than zero.[49]

Streamflows in Pocket Creek, as in all surface waters, vary considerably throughout the year and from year to year. However, with estimates of 7Q10 flows at zero cubic feet per second it is fairly clear that flows in Pocket Creek are very low for extended periods of time. It is likely there would be times when flows would be sufficient for 3.9 cfs withdrawals for two days to provide 5 million gallons of water. But without the authority to regulate withdrawals the contractors could take the water when it was most convenient for them and the resource management agencies and other water users would have to deal with the consequences. In a stream of this size there will be significant periods of time when withdrawals of 3.9 cfs would not leave enough water to support aquatic life, ensure good water quality, and protect the rights of other landowners to also make beneficial use of the water. It is currently unclear if DENR would have the authority to prevent this situation from happening. If not, then the department would not have the authority to prevent a situation where all three of these well sites chose to withdraw this volume of water at the same time or on successive days if it suited their operations.

The Water Use Act of 1967 provides a tool to manage water withdrawals in situations where the Environmental Management Commission decides regulation is needed to protect the interests and rights of residents and property owners or the public interest.[50] This act has historically provided an after-the-fact remedy to address impacts that are already limiting the use of a water source. After an investigation to document the need for regulation the EMC develops and adopts rules to regulate water withdrawals within a designated Capacity Use Area. Rules are designed to remedy the problems identified in the study with the goal of preventing further detrimental impacts and supporting resource recovery. This act provides a

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[48] Giese, G.L., and R.R. Mason, Jr. "Low-flow characteristics of streams in North Carolina: U.S. Geological Survey Water-Supply Paper 2403." USGS, 1993.

[49] Giese and Mason, 1993, in Table 1 provide a 7Q10 estimated for the Beaverdam Creek watershed in Granville County, a 44.2 square mile drainage area classified as HA6, of zero cubic feet per second.

[50] N.C. General Statute § 143-215.11 et. seq.

mechanism to recover rights to waters of the State for North Carolina citizens that could have been preserved by prior actions to regulate water withdrawals to maintain sufficient water resources to support aquatic life, ensure good water quality, and protect the rights of landowners to make beneficial use of the water.

Actual water use for gas well development may be different than the amounts analyzed here. If laws are adopted to minimize impacts at this projected level of water usage, then actual water use may be less than the estimates presented here.

Conclusions related to water supply

With wise management, adequate water supplies would likely be available to meet the needs of the shale gas extraction in the vicinity of the Triassic Basins in North Carolina. However, there is no clear, existing regulatory path or framework that gives any state agency the ability to ensure that groundwater or surface water withdrawals for natural gas exploration are appropriately managed to avoid stream impacts and conflicts with other water users.

Available information indicates that drilling and hydraulic fracturing of natural gas wells typically uses from three to five million gallons of water per well. According to a fact sheet by Chesapeake Energy entitled "Water Use in Deep Shale Gas Exploration," dated May 2011, "the company uses a variety of water sources depending on availability."[51] To quote the fact sheet, "This water is typically transported via temporary pipelines or trucked to drilling locations for storage prior to use in tanks or impoundments."

If the necessary volumes of water can be accumulated over an extended period of time rather than only on the days when hydraulic fracturing is actually occurring, then needs could be met by smaller withdrawals from a larger set of potential sources. If available sources could support larger withdrawals, because of stream size or seasonally higher flows, then overall withdrawal times could be reduced. It is not possible to develop a more specific characterization of water needs and available sources prior to the initiation of shale gas development operations and the resulting determination of the site-specific needs in the Triassic Basins of North Carolina. However, most of the areas where natural gas exploration is expected to occur do appear to possess the capability to support additional surface water withdrawals and continue to support the needs of the local population.

Some public water systems in the vicinity of the Triassic Basins may have unused capacity that could supply water for shale gas exploration and production. These water sources have already been evaluated for their potential environmental impacts at their maximum withdrawal levels. Therefore, the time and expense of evaluating potential impacts of new withdrawals could be avoided. Increased water sales would be a boost to utility revenues and their ability to cover the costs of existing debt. The relatively short-term nature of gas well drilling and development would allow the option for time-limited commitments on the part of the utilities to take advantage of currently unused capacity, while at the same time keeping that capacity available

[51] Chesapeake Energy. "Water Use in Deep Shale Gas Exploration." 2011. Retrieved January 9, 2012 from http://www.naturalgaswaterusage.com/Pages/information.aspx.

in the future to provide water to a growing customer base. Details on the volume of water made available and duration of the commitment would be subject to negotiation between the parties.

Many local government and large community water systems across the state have seen their per capita demand for water decline because of their customers' experiences during recent droughts. For many systems, daily water use has not returned to the levels seen prior to drought response activities over the last decade. This phenomenon, combined with the downturn in economic expansion and the exodus of manufacturing facilities, has put some water utilities in the position of making payments on debts for unused system capacity. In addition, reduced per capita demand has resulted in reduced revenues to cover debt payments.

According to data in the 2010 local water supply plans, Sanford, Eden, Mayodan, Madison, Anson County and Montgomery County water systems do not currently use all the water available to them. Local plan data indicate that, based on water treatment plant capacities, the surface water systems in the Dan River hydrologic sub-basin could have about 17 million gallons per day available on an average day basis. In the Wadesboro geologic sub-basin, Montgomery County could have about three million gallons per day available on average, and in the Sanford geologic sub-basin the city of Sanford could have about six million gallons per day available on average for the next few years. Several of these systems do not indicate in their local water supply plans needing the total volume of their available supplies before 2060. Of course, the ability to make use of this water depends on the ability of the parties to come to a mutually acceptable agreement.

DENR suggests that the gas industry and public water utilities work together to meet water needs for gas exploration while protecting water quality and the rights of other water users and encourages the investigation of options to satisfy water needs by taking advantage of unused capacity at existing withdrawal facilities.

DENR recommends that new surface water withdrawals for gas wells be limited such that the cumulative instantaneous withdrawals in the vicinity of the intake do not exceed 20 percent of the 7Q10 flow. Instantaneous withdrawals greater than 20 percent of the 7Q10 should require site-specific evaluations of potential impacts. This threshold has been used for many years and has been shown to be protective of other existing water users and the environment. This approach has several inherent advantages: it would protect small watersheds with low 7Q10 flows and the existing water users; it would be naturally protective during low-flow conditions and droughts; it would prevent excessive withdrawals during periods of peak usage, it would be consistent with existing state protocols; and it would prevent any surface water in North Carolina from drying up due to natural gas withdrawals.

Much of this analysis focused on surface water resources because of the historically low yields available from wells drilled in the Triassic Basins. Higher yields have been produced from some wells drilled in these areas, but the ability to estimate yields prior to investing in drilling a water supply well is limited by the highly variable nature of the fracture networks that may or may not be intersected by a wellbore.

Table 3-18 provides yield information for the public water supply wells located in the Triassic Basins. Groundwater is available from a well because it can move into the well bore through the network of pathways in the rock formations. The uncertainty of the nature of these pathways also makes it difficult to predetermine the possible impacts on neighboring wells from the addition of new wells within or near shared fracture networks. Because of the variability of groundwater resources, DWR cautions that they may be inadequate to meet water needs for hydraulic fracturing operations.

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Table 3-18. Triassic Public Water Supply Wells (gpm = gallons per minute)

Subwatershed	Geologic Unit	Geologic Formation	Public Water Supply #	Source Name	Depth (feet)	Yield (gpm)	Yield (mgd)	Yield (cfs)
Chatham County								
030300020604	TRc	Chatham Group-Undivided	4019004	WELL #7	1000	39	0.056	0.087
030300020604	TRc	Chatham Group-Undivided	4019004	WELL #4	400	49	0.071	0.109
030300020604	TRc	Chatham Group-Undivided	4019004	WELL #2	400	41	0.059	0.091
030300020604	TRc	Chatham Group-Undivided	4019004	WELL#1A	400	14	0.020	0.031
030300020604	TRc	Chatham Group-Undivided	0319439	WELL #1	225	5	0.007	0.011
030300020605	TRc	Chatham Group-Undivided	4019015	WELL #2	500	98	0.141	0.219
030300020605	TRc	Chatham Group-Undivided	0319440	WELL #1	28	60	0.086	0.134
030300020608	TRc	Chatham Group-Undivided	0319456	WELL #1	Unk.	60	0.086	0.134
030300020608	TRc	Chatham Group-Undivided	0319424	WELL #1	Unk.	60	0.086	0.134
030300020608	TRc	Chatham Group-Undivided	0319471	WELL #2	305	7	0.010	0.016
030300020608	TRc	Chatham Group-Undivided	4019016	WELL#1	Unk.	10	0.014	0.022
030300020608	TRc	Chatham Group-Undivided	0319457	WELL #1	110	10	0.014	0.022
030300020608	TRc	Chatham Group-Undivided	0319124	WELL #2	120	15	0.022	0.033
030300020608	TRc	Chatham Group-Undivided	0319124	WELL #1	125	25	0.036	0.056
030300020610	TRc	Chatham Group-Undivided	4019020	WELL #1	365	10	0.014	0.022
030300020610	TRc	Chatham Group-Undivided	0319469	WELL #1	125	60	0.086	0.134
030300020610	TRc	Chatham Group-Undivided	0319425	WELL #6	411	20	0.029	0.045
030300020610	TRc	Chatham Group-Undivided	0319425	WELL #8	320	120	0.173	0.268
030300020610	TRc	Chatham Group-Undivided	0319426	WELL #1	162	30	0.043	0.067
030300020610	TRc	Chatham Group-Undivided	0319428	WELL #1	250	70	0.101	0.156
030300020610	TRc	Chatham Group-Undivided	0319136	WELL #1	145	120	0.173	0.268
030300020705	TRcp	Pekin Formation	0319125	WELL A	130	24	0.035	0.054
030300020705	TRcp	Pekin Formation	0319125	WELL B	220	14	0.020	0.031
030300040104	TRcs	Sanford Formation	0319463	WELL #1	180	60	0.086	0.134
Durham County								
030202010403	TRc	Chatham Group-Undivided	0332584	WELL #1	100	10	0.014	0.022
030202010404	TRc	Chatham Group-Undivided	0332135	WELL #1	325	55	0.079	0.123
030202010404	TRc	Chatham Group-Undivided	0332580	WELL #1	Unk.	60	0.086	0.134
030202010404	TRc	Chatham Group-Undivided	0332575	WELL #1	Unk.	60	0.086	0.134
030202010502	TRc	Chatham Group-Undivided	0332526	WELL #1	Unk.	60	0.086	0.134
030202010502	TRc	Chatham Group-Undivided	0332554	WELL #1	Unk.	60	0.086	0.134
030202010502	TRc	Chatham Group-Undivided	0332109	WELL #3	205	37	0.053	0.083
030202010504	TRc	Chatham Group-Undivided	0332106	WELL #1	146	60	0.086	0.134
030202010504	TRc	Chatham Group-Undivided	0332106	WELL #2	255	30	0.043	0.067
030202010504	TRc	Chatham Group-Undivided	0332106	WELL #4	303	100	0.144	0.223
030202010504	TRc	Chatham Group-Undivided	0332141	WELL #32	300	30	0.043	0.067
030202010504	TRc	Chatham Group-Undivided	0332141	WELL #9	250	65	0.094	0.145
030202010504	TRc	Chatham Group-Undivided	0332528	WELL #1	Unk.	60	0.086	0.134
030202010504	TRc	Chatham Group-Undivided	0332582	WELL #1	Unk.	60	0.086	0.134
030202010504	TRc	Chatham Group-Undivided	4032016	WELL #1	Unk.	12	0.017	0.027
030202010801	TRc	Chatham Group-Undivided	0332574	WELL #1	Unk.	60	0.086	0.134
030202010801	TRc	Chatham Group-Undivided	0332590	WELL #1	265	10	0.014	0.022
030202010802	TRc	Chatham Group-Undivided	0332571	WELL #1	Unk.	60	0.086	0.134
030300020601	TRc	Chatham Group-Undivided	0332453	WELL #1	Unk.	60	0.086	0.134
030300020604	TRc	Chatham Group-Undivided	0332441	WELL #2	Unk.	80	0.115	0.178
Lee County								
030300030603	TRcs	Sanford Formation	0353127	WELL #3	405	5	0.007	0.011
030300030603	TRcs	Sanford Formation	0353127	WELL #1	300	76	0.109	0.169
030300030603	TRcs	Sanford Formation	0353127	WELL #4	300	25	0.036	0.056
030300030607	TRcs	Sanford Formation	0353420	WELL #1	100	60	0.086	0.134
Granville County								
030202010404	TRc	Chatham Group-Undivided	0239495	WELL #2	345	1	0.001	0.002
030202010404	TRc	Chatham Group-Undivided	0239495	WHITE RABBIT WELL #3	405	10	0.014	0.022
030202010501	TRc	Chatham Group-Undivided	0239446	WELL#1	200	15	0.022	0.033
030202010503	TRc	Chatham Group-Undivided	0239435	WELL #1	150	60	0.086	0.134
Montgomery County								
030401040401	TRc	Chatham Group-Undivided	0362562	WELL #1	Unk.	80	0.115	0.178
030401040402	TRc	Chatham Group-Undivided	0362436	WELL #1	180	180	0.259	0.401

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Table 3-18 (continued) Triassic Public Water Supply Wells (gpm = gallons per minute)

Subwatershed	Geologic Unit	Geologic Formation	Public Water Supply #	Source Name	Depth (feet)	Yield (gpm)	Yield (mgd)	Yield (cfs)
Moore County								
030300030301	TRcp	Pekin Formation	0363500	WELL #1	Unk.	60	0.086	0.134
030300030302	TRcp	Pekin Formation	0363447	WELL #1	100	10	0.014	0.022
030300030302	TRcp	Pekin Formation	0363448	WELL #1	303	60	0.086	0.134
030300030303	TRcs	Sanford Formation	0363429	WELL #1	50	60	0.086	0.134
030300030408	TRcp	Pekin Formation	0363436	WELL #1	Unk.	60	0.086	0.134
030300030601	TRcs	Sanford Formation	0363541	WELL #1	200	40	0.058	0.089
030300030601	TRcs	Sanford Formation	0363538	WELL #1	Unk.	60	0.086	0.134
030300030601	TRcs	Sanford Formation	0363527	WELL #1	186	7	0.010	0.016
030300030604	TRcc	Cumnock Formation	0363470	WELL #1	Unk.	60	0.086	0.134
030300040305	TRcs	Sanford Formation	0363537	WELL #1	110	41	0.059	0.091
Orange County								
030300020601	TRc	Chatham Group-Undivided	0368444	WELL #1	Unk.	60	0.086	0.134
Rockingham County								
030101030305	TRds	Stoneville Formation	0279741	WELL #1	176	4	0.006	0.009
030101030306	TRds	Stoneville Formation	0279455	WELL #1	175	20	0.029	0.045
030101030306	TRdp	Pine Hall Formation	0279150	WELL #1	545	22	0.032	0.049
030101030409	TRds	Stoneville Formation	0279625	WELL #1	Unk.	60	0.086	0.134
030101030503	TRds	Stoneville Formation	0279505	WELL #1	Unk.	60	0.086	0.134
030101030503	TRds	Stoneville Formation	3079003	WELL #1	Unk.	60	0.086	0.134
030101030503	TRds	Stoneville Formation	3079025	WELL #2	400	14	0.020	0.031
030101030503	TRds	Stoneville Formation	3079025	WELL #1	385	5	0.007	0.011
030101030503	TRdc	Cow Branch Formation	3079004	WELL#2	210	7	0.010	0.016
Stokes County								
030101030203	TRds	Stoneville Formation	0285101	WELL #1	315	25	0.036	0.056
030101030203	TRds	Stoneville Formation	0285447	WELL #9	305	25	0.036	0.056
030101030203	TRds	Stoneville Formation	0285455	WELL #1	Unk.	60	0.086	0.134
030101030203	TRds	Stoneville Formation	0285015	WELL #1-FIRE STATION	1230	140	0.202	0.312
030101030203	TRds	Stoneville Formation	0285015	WELL #2-FOWLER PARK	1150	95	0.137	0.212
030101030203	TRds	Stoneville Formation	0285015	WELL #6-BICYCLES WELL	903	40	0.058	0.089
030101030204	TRds	Stoneville Formation	0285015	WELL #3	600	35	0.050	0.078
030101030204	TRds	Stoneville Formation	0285015	WELL #4-CLUB STREET	805	55	0.079	0.123
030101030204	TRdc	Cow Branch Formation	0285015	WALNUT TREE WELL	130	126	0.181	0.281
030101030302	TRds	Stoneville Formation	3085005	WELL #1	265	10	0.014	0.022
030101030302	TRds	Stoneville Formation	0285015	WELL #5-HWY 311	605	36	0.052	0.080
030101030306	TRds	Stoneville Formation	0285401	WELL #1	200	5	0.007	0.011
030101030306	TRds	Stoneville Formation	0285473	WELL #6	268	100	0.144	0.223
030101030306	TRds	Stoneville Formation	0285473	WELL #1	465	100	0.144	0.223
030101030306	TRds	Stoneville Formation	0285473	WELL #7	300	50	0.072	0.112
030101030306	TRds	Stoneville Formation	0285473	WELL #8	400	50	0.072	0.112
030101030306	TRds	Stoneville Formation	0285473	WELL #5	100	100	0.144	0.223
030101030306	TRds	Stoneville Formation	0285419	WELL #1	Unk.	60	0.086	0.134
030101030306	TRdp	Pine Hall Formation	0285435	WELL #1	Unk.	60	0.086	0.134
030101030306	TRdc	Cow Branch Formation	0285428	WELL #1	175	50	0.072	0.112
Wake County								
030202010502	TRc	Chatham Group-Undivided	0392373	CHESTNUT OAKS_WELL #2	605	106	0.153	0.236
030202010503	TRc	Chatham Group-Undivided	4392121	WELL #2	255	9	0.013	0.020
030202010503	TRc	Chatham Group-Undivided	4392121	WELL #1	455	20	0.029	0.045
030202010503	TRc	Chatham Group-Undivided	4392479	WELL #2	300	7	0.010	0.016
030202010504	TRc	Chatham Group-Undivided	0392788	WELL #3 SB2	352	43	0.062	0.096
030202010504	TRc	Chatham Group-Undivided	0392788	WELL #2 SB3	304	12	0.017	0.027
030202010504	TRc	Chatham Group-Undivided	0392788	WELL #1 SB9	394	37	0.053	0.083
030300020608	TRc	Chatham Group-Undivided	4392514	WELL #1	Unk.	60	0.086	0.134
030300020608	TRc	Chatham Group-Undivided	0392416	WELL #1	Unk.	60	0.086	0.134
030300020609	TRc	Chatham Group-Undivided	0392448	WELL #1	Unk.	60	0.086	0.134
030300020609	TRc	Chatham Group-Undivided	0392672	WELL #1	Unk.	60	0.086	0.134
030300020609	TRc	Chatham Group-Undivided	4392505	WELL #1	Unk.	60	0.086	0.134
030300040102	TRc	Chatham Group-Undivided	4392520	WELL #1	300	2	0.003	0.004
030300040102	TRc	Chatham Group-Undivided	4392521	WELL #2	380	20	0.029	0.045
030300040102	TRc	Chatham Group-Undivided	0392271	WELL #2	300	15	0.022	0.033
030300040102	TRc	Chatham Group-Undivided	0392660	WELL #1	Unk.	60	0.086	0.134

B. Road and bridge infrastructure

Existing condition and effects of increased use

As with any industrial activity, natural gas extraction requires the use of vehicles and machinery. The types of vehicles and machinery most commonly used in the process of natural gas extraction are employee and delivery vehicles, specialized cement equipment and vehicles, flatbed tractor trailers and trucks to transport water, sand and chemicals.

Water can be delivered to the well pad either by trucks or by pipelines. Since pipelines do not yet exist in the Triassic Basin, it is likely that, water would be transported by truck for the first several years. One source states that one gas well service company uses tanker trucks that carry 5,460 gallons of water to transport water to the well pad.[52] A staff person at Chesapeake Energy Corporation, which conducts shale gas exploration and production using hydraulic fracturing in Pennsylvania and other states, said f its trucks for transporting water hold between 4,000 and 5,000 gallons of water.[53]

Fracturing additives are transported in trucks or containers, typically flatbed trucks that carry plastic totes that hold the liquid additives. Liquid products used in smaller quantities are transported in one-gallon sealed jugs carried in the side boxes of the flatbed. Some additives, such as hydrochloric acid, are transferred in tanker trucks. Dry additives are transported on flatbeds in 50- or 55-pound bags set on pallets containing 40 bags each and shrink-wrapped, or in five-gallon sealed plastic buckets. Smaller quantities may be transported in the side boxes of trucks.[54] The flatbed trucks that deliver liquid totes to the site may be equipped with pumping systems for transferring the liquid. Sand or other proppants used in hydraulic fracturing are transported from their mined sources by rail or truck to the well pad.

In New York and Pennsylvania, additives are transported in trucks that are approved by U.S. Department of Transportation (USDOT) regulations. The New York State Department of Transportation (NYSDOT) has adopted federal regulations for transporting hazardous materials interstate and has adopted state standards for intrastate transportation.

For shale gas exploration and production using hydraulic fracturing, the number of trucks used would be particularly heavy during the first 50 days of the well pad development, when water and additives are transported to the site for hydraulic fracturing and wastewater may be trucked away from the site. The New York State Department of Environmental Conservation estimated the number of trucks required for a new well location during the early development of the shale play, and also for the peak development year for the shale play, when some water maybe transported by pipeline rather than by truck. Although the timeframe for this estimate is not provided, the report provides "the estimated duration of the various phases of activity

[52] Shaleshock. "Drilling 101." Retrieved January 26, 2012 from http://shaleshock.org/drilling-101/.
[53] Personal communication, February 1, 2012.
[54] NYSDEC, pp. 5-79 – 5-80.

involved in the completion of a typical installation."[55] This timeframe ranges from 40 to 61 days, as shown in Table 3-19 below.

Table 3-19. NYSDEC Assumed Construction and Development Times[56]

Operation	Estimated Duration (days)
Access roads	3 - 7
Site preparation/well pad	7 - 14
Well drilling	28 - 35
Hydraulic fracturing single well	2 - 5

During early shale play development, NYSDEC estimates 1,148 one-way heavy-duty truck trips per well during construction and 831 one-way light-duty truck trips per well during construction. For early well pad development, this is a total of 2,296 round-trip heavy-duty truck trips[57] and 1,662 round-trip light-duty truck trips per well when all water is transported by truck. During the peak development period of the shale play, when pipelines are assumed to be used for some water transport, NYSDEC estimates 625 one-way heavy-duty truck trips per well and 831 one-way light-duty truck trips per well.[58] For peak well pad development, this is a total of 1,250 round-trip heavy-duty truck trips and 1,662 round-trip light-duty truck trips. These figures are shown by stage of the well development process in Table 3-20.

[55] NYSDEC, p. 6-298.
[56] This table is copied from NYSDEC, p. 6-298.
[57] The number as reported in NYSDEC's Draft Supplemental Generic Environmental Impact Statement is actually 3,950, however, we believed this to be a typographical error, since (831 + 1,148) * 2 = 3,958.
[58] The number of one-way light-duty truck trips per well is reported as 795, however, the numbers in Table 3-20 add up to 831 (this table appears in the NYSDEC Draft Supplemental Generic Environmental Impact Statement). For a breakdown of truck trips used for this estimate by the type of materials being hauled, see NYSDEC, p. 6-302.

Table 3-20. Estimated Number of One-Way (Loaded) Trips per Well: Horizontal Well[1]

Well Pad Activity	Early Well Pad Development (all water transported by truck)		Peak Well Pad Development (pipelines may be used for some water transport)	
	Heavy Truck	Light Truck	Heavy Truck	Light Truck
Drill pad construction	45	90	45	90
Rig mobilization[2]	95	140	95	140
Drilling fluids	45		45	
Non-rig drilling equoipment	45		45	
Drilling (rig crew, etc.)	50	140	50	140
Completion chemicals	20	326	20	326
Completion equipment	5		5	
Hydraulic fracturing equipment (trucks and tanks)	175		175	
Hydraulic fracturing water hauling[3]	500		60	
Hydraulic fracturing sand	23		23	
Produced water disposal	100		17	
Final pad prep	45	50	45	50
Miscellaneous	-	85	-	85
Total One-Way, Loaded Trips per Well	**1,148**	**831**	**625**	**831***

* This number is reported in New York's Draft Supplemental Generic Environmental Impact Statement as 795, however, the numbers in the column total to 831.

Source: This table is copied from the New York State Department of Environmental Conservation's Draft Supplemental Generic Impact Statement, p. 6-302. Their source for the table is ALL Consulting. Their footnotes to the table are below.

"1. Estimates are based on the assumption that a new well pad would be developed for each single horizontal well. However, industry expects to initially drill two new wells on each well pad, which would reduce the number of truck trips. The well pad would, over time, be developed into a multi-well pad.

2. Each well would require two rigs, a vertical rig and a directional rig.

3. It was conservatively assumed that each well would use approximately 5 million gallons of water total and that all water would be trucked to the site. This is substantially greater than the likely volume of water that would be trucked to the site."

If 164 wells are drilled in North Carolina in a single year (the maximum number of wells that could be drilled in a year, as posited in Table 3-17), and 2,296 heavy-duty round-trip truck trips and 1,662 light-duty round-trip truck trips are required for those wells, activity in the Dan and Deep River Basin would result in an additional 649,112 truck trips per year. Using the NYSDEC's estimate for peak development of the shale play, when some water is transported by pipeline rather than truck, those same 164 wells would result in an additional 477,568 round-trip truck trips per year. As noted earlier in the report it is unlikely that 164 wells would be drilled in a single year.

The increase in heavy-duty truck traffic can have implications for the condition and long-term maintenance of roads. Some of these trucks can weigh as much as 80,000 to 100,000 pounds when fully loaded,[59] and due to the vehicle's weight, heavy trucks in general cause more damage to roads and bridges than cars or light trucks. Road damage could range from minor cracking to potholes, rutting or complete failure.

Existing road conditions

Staff of the N.C. Department of Transportation (NCDOT) analyzed a sample of roads in each of seven counties within the Triassic Basins (Anson, Chatham, Lee, Moore, Richmond, Rockingham and Stokes counties), examining the average pavement condition rating for each county and the average percentage of alligator cracking on the road sections (interconnecting cracks in pavement that form a pattern resembling an alligator's skin) in each of the counties.[60] NCDOT defines pavement condition as the percent of highway lane miles in good condition, and "good condition for pavement is defined as a Pavement Condition Rating (PCR) of 80 or higher."[61] Based on the analysis of a small sample of roads in these counties, the road sections analyzed had more than 15 percent alligator cracking for each county except Stokes County. Pavement conditions were poorest in Chatham and Moore counties. Summary statistics for these counties are shown in Table 3-21.

Table 3-21. Pavement Conditions in Sample of Roads in the Triassic Basin

County	Pavement Condition Rating	% Alligator Cracking	Number of Routes in Sample
Anson	88.13	15.42	24
Chatham	76.06	41.94	62
Lee	83.43	25.91	22
Moore	78.13	33.64	33
Richmond	88.02	17.92	24
Rockingham	88.98	15.6	25
Stokes	93.52	6.67	28

Many of the secondary roads in the area of the Deep and Dan river basins are constructed to deal with very few heavy trucks. According to NCDOT, the secondary roads in these areas are "thin pavements built on unimproved subgrade and can be expected to tear up under the heavy repeated loadings" associated with shale gas exploration and production activities.[62] Larger roads, such as interstate highways, receive more frequent maintenance than smaller, local roads, which are more likely to be used for gas drilling operations.

[59] Marcellus-Shale.us. "Our Look at Road Damage from Heavy Truck Traffic." Retrieved February 29, 2012 from http://www.marcellus-shale.us/road_damage.htm.
[60] Personal communication, February 10, 2012.
[61] North Carolina Department of Transportation. *Performance Dashboard Documentation*. September 15, 2010, p. 3. Retrieved February 16, 2012 from http://www.ncdot.gov/download/performance/dashboarddetails.pdf.
[62] Personal communication, February 10, 2012.

NCDOT staff analyzed the impact of additional truck traffic to a typical roadway currently receiving a low volume of traffic. The road analyzed is a new road, beginning in good condition, consisting of three inches of asphalt on six inches of aggregate base. With existing minimal trucks, this type of design is expected to last 20 years. With only an additional 100 heavy-duty trucks per day from natural gas drilling and production, the road would fail in less than two years. Based on NCDOT's sample, roads in the Triassic Basin are not all in good condition currently, and may fail in even less time.[63]

Bridges in all areas of the Triassic Basin may not provide clearance for the height of heavy-duty trucks. Table 10-1 in Appendix A: Bridges in the Triassic Basins with minimum clearance shows 220 bridges in the areas underlain by the Triassic Basins with minimum clearance.

Costs for road repair or replacement

The NYSDEC states that it cannot estimate costs associated with roads and bridges because:

> "these costs are a factor of (1) the number, location, and density of wells; (2) the actual truck routes and truck volumes; (3) the existing condition of the roadway; (4) the specific characteristics of the road or bridge (e.g., the number of lanes, width, pavement type, drainage type, appurtenances, etc.); and (5) the type of treatment warranted."[64]

However, within NYSDEC's draft environmental impact statement, the New York State Department of Transportation (NYDOT) estimated that the replacement costs for a bridge could range from $100,000 to $24 million per bridge, with an average of $1.5 million per bridge. NYDOT estimated the cost to repair local roads to range from $70,000 to $150,000 per lane mile for low-level maintenance to $400,000 to $530,000 per lane mile for higher-level maintenance. Total reconstruction could range from $490,000 to $1.9 million per lane mile.[65]

Estimates to repair or replace state bridges and roads were even higher. State bridge replacement could range from $100,000 to $31 million per bridge, averaging $3.3 million per bridge. Low-level maintenance for state roads would range from $90,000 to $180,000 per lane mile; higher-level maintenance would range from $540,000 to $790,000 per lane mile. "Full depth reconstruction" can range from $910,000 to $2.1 million per lane mile.[66]

Road construction costs are variable based on topography and area of the country. It is recommended that further research be conducted to assess the potential costs to North Carolina.

Depending on the amount of natural gas extraction and production that occurs, there is a possibility that bridges and state roads would require more frequent maintenance and possibly replacement. However, as NYSDEC points out, it is difficult to calculate how much damage to state roads would be attributable to hydraulic fracturing. The impacts from this activity may be

[63] Personal communication, February 13, 2012.
[64] NYSDEC, p. 6-312.
[65] Ibid, p. 6-312.
[66] Ibid, p. 6-313.

clearer on local roads, which do not generally experience a high volume of industrial truck traffic and are therefore built to lower standards. As NYSDEC states, on local roads, "actual contribution of heavy trucks to road and bridge deterioration would be greater than suggested by their proportion to total traffic."[67]

Safety considerations

Any increase in traffic can lead to an increase in accidents on the road. Moreover, an increase of heavy-duty trucks on narrow roads not built to accommodate the larger widths and weights of these trucks would have an even greater likelihood of increasing the number of accidents. To mitigate such impacts, local governments and NCDOT can install safety features, such as turn lanes and traffic signals. For local roads, NYSDEC estimates that installing a turn lane could cost from $17,000 to $34,000, the installation of a flashing red or yellow signal could cost $35,000, and the installation of a three-color signal could range from $100,000 to $150,000.

Road impacts

Some communities where shale gas drilling has rapidly increased experience road and bridge damage that places a financial burden on the local government and distresses residents who use the roads. In a conversation with DENR staff and four members of the N.C. House of Representatives, one Bradford County, Pennsylvania official said of the traffic in Towanda (a town of approximately 3,000 people), "There have been days when it takes 40 minutes to drive three miles."[68] Bradford County officials also said that trucks for drilling operations have gotten stuck in ditches, requiring local government emergency management services to extract them, and that trucks have "taken out traffic lights and bridges."[69]

Penn State Cooperative Extension conducted a study of how gas development is affecting the demand for municipal government services in Susquehanna and Washington counties. Cooperative Extension staff performed statistical analysis of local government audit data and held focus group interviews with 17 municipal officials from both counties. Penn State Cooperative Extension reports:

> "Road impacts were by far the main issue municipal officials raised with us in the interviews. Gas development creates significant increases in truck and other traffic, and wear and tear on roads is often very visible. For many of Pennsylvania's smallest townships, road maintenance and repair historically accounts for the largest share of their spending."[70]

In many cases, drilling operators have worked to resolve issues related to roads. Bradford County officials said that once drilling operators saw the damage being caused to roads, they were proactive about repairing them. Drilling operators have established "road use and maintenance agreements" (RUMA) with some towns in Pennsylvania. Penn State Cooperative

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[67] Ibid, p. 6-314.
[68] Personal communication, February 2, 2012.
[69] Ibid.
[70] Penn State Cooperative Extension. Impacts of Marcellus Shale Development on Municipal Governments in Susquehanna and Washington Counties, 2010. The Pennsylvania State University, 2011.

Extension reports that the township officials who were interviewed "generally were very satisfied with the quality of the repairs and upgrades, and noted that company policies are to leave the roads in equal or better condition than before the gas development began."[71] In one township, more than a third of their roads had been repaired.[72]

In Pennsylvania, RUMAs are common. According to a Chesapeake Energy PowerPoint, they have "been used extensively for Chesapeake's operations area in Pa." Under a typical RUMA, the operator agrees to reimburse the municipality or county "for any additional costs incurred, associated with the maintenance of said roadway as a result of the Operator's activities during construction, drilling and completion" of wells. The operator also agrees "to maintain roads to a condition consistent with that prior to operations [and] assumes all liability for subcontractors working on Operators behalf." Chesapeake will perform the road maintenance to the local government's specifications, or the local government can perform the work itself.[73]

There are some downsides to RUMAs. Roads are sometimes repaired using higher quality materials or have larger dimensions than the original road. This can require additional costs on the part of the local government for maintenance and repair, especially if the roads have been widened. In addition, township officials reported to Penn State Cooperative Extension, "major difference between companies on how they dealt with roads," and while some companies were proactive, others "were more reactive or even difficult to contact and less communicative."[74]

Rather than leaving each individual municipality or county to negotiate its own agreement with drilling operators, some states have considered developing a model road use and maintenance agreement. The County Commissioners Association of Ohio and the Ohio Township Trustee Association worked on the development of a model agreement and discussed the possibility that the Ohio Department of Natural Resources could require that an agreement be in place with the local government before issuing a drilling permit. However, at a recent meeting with the Ohio Department of Transportation, the Ohio Department of Natural Resources and the Office of Governor John Kasich, "a number of stakeholders were surprised when officials said that rather than require a RUMA as a condition to an ODNR permit to drill, ODNR will instead mimic the concentrated animal feeding operation (CAFO) process by only inquiring whether a RUMA is in place or if good faith efforts have been made to negotiate a RUMA," and if the answer to either question is yes, the permit will be granted.[75]

Weight limits

In addition to community concerns about traffic and road maintenance, there have also been concerns expressed about trucks exceeding weight limits on roads. Shale gas drilling often takes

[71] Ibid.
[72] Ibid.
[73] Chesapeake Energy. "Chesapeake Energy Shale Operations Overview." Retrieved March 1, 2012 from http://jfs.ohio.gov/owd/Initiatives/Docs/Chesapeake-Ohio-Basic-Drilling.pdf.
[74] Penn State Cooperative Extension, 2011.
[75] County Commissioners Association of Ohio. "Update on Oil & Gas Road Use Maintenance Agreements." *Statehouse Report*, February 17, 2012. Retrieved March 1, 2012 from http://www.ccao.org/Portals/0/Statehouse/SHR20120217.pdf.

place in rural areas where weigh stations are infrequent. In Jefferson County, Pa., one farmer lost patience with hydraulic fracturing trucks repeatedly driving down a road that had a 10-ton weight limit and was off-limits to heavy-duty trucks. After the state police told the farmer they would have to catch truck drivers in the act, the farmer blocked the road with his pickup, trapping heavy-duty trucks on the road, and holding them there until state troopers arrived to issue fines and citations.[76]

In Pennsylvania, heavy-duty trucks can drive on roads with a vehicle in excess of the weight limit if the truck is bonded and the company has entered into a maintenance agreement with the road owner. The maintenance agreement establishes the responsibility of the truck owner to pay for excess maintenances costs for the roadway due to the heavy hauling activities.[77] According to Penn State Cooperative Extension, most of the townships interviewed from Washington County had performed "road engineering studies to allow posting weight limits on the road, while in Susquehanna County only one township had done so."[78] These studies are performed at the expense of the local government.

Management Options

Several options exist for managing the impacts to road and bridge infrastructure from natural gas exploration and production:

- Patch or otherwise improve roads prior to beginning shale gas exploration and production.
- Require a bond from the gas operator sufficient to perform full-depth reclamation on all roads used for hauling in the likely event that the roads are damaged. In Pennsylvania, "in order to have a case in court, municipalities must post weight limits on roads prior to hauling activity. After posting, the municipality may permit heavier loads to be hauled on the road and may require a bond from the hauler."[79]
- Build up the roadways in advance, which would require advanced knowledge of which roads will be used.
- Require gas operators to enter into road use and maintenance agreements prior to natural gas drilling.
- Ask drilling operators to provide NCDOT with well locations and haul routes in advance. This would allow NCDOT to try to minimize damage and prepare a photographic log of existing pavement conditions in the event of damage.

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[76] Phillips, Susan. "Fed Up Farmer Uses Pickup to Block Frack Trucks." StateImpact. February 27, 2012. Retrieved February 28, 2012 from http://stateimpact.npr.org/pennsylvania/2012/02/27/fed-up-farmer-uses-pickup-to-block-frack-trucks/.

[77] Bradford County Government. "Natural Gas Information." Retrieved Febraury 28, 2012 from http://www.bradfordcountypa.org/Natural-Gas.asp?specifTab=5.

[78] Penn State Cooperative Extension, 2011.

[79] Lovegreen, Mike. "Impacts of Marcellus Well Drilling on Local Communities." PowerPoint presentation. February 2, 2012.

We recommend that the General Assembly direct the North Carolina Department of Transportation to study the issue of road management and options for mitigating the impacts of increased traffic on roads, such as requiring bonds or road use management agreements.

C. Transportation methods

Rail transportation

If shale gas exploration and production comes to North Carolina, a large amount of pipe, drilling equipment, chemicals and other materials would have to be transported from manufacturing facilities to well pads. Many of these materials will be transported from manufacturing facilities by rail to rail depots, and from rail depots by trucks to well pads. The use of rail depots for transporting the large amount of material associated with shale gas exploration and production would likely increase truck traffic near rail depots and on roads in the vicinity of rail depots.

Transportation of fresh water

Fresh water is one material that would likely not be transported by rail. Water could be delivered from the source to the well pad by truck or by overland pipeline. Recently, some shale gas operators have begun building centralized surface water impoundments that can serve several well pad sites. Water is transported from the source by overland pipeline to the surface water impoundment and then trucked from the surface water impoundment to the well pads that it serves. Surface water impoundments allow operators to withdraw water during periods of high flow and store the water for use during hydraulic fracturing. This reduces the need for operators to withdraw water during periods of low flow, which can have negative impacts on aquatic environments and water supply for other users. These impoundments can serve well pads within a radius of four miles, and "impoundment volume could be several million gallons with surface acreage of up to five acres."[80] Surface water impoundments may present an attractive nuisance to wildlife such as birds and deer – this may be mitigated by installing fencing and netting.

Transportation of gas

The gas transportation system

Once natural gas leaves the well, it enters gathering lines, which are low pressure, small diameter (6-20 inches) steel pipes that carry raw natural gas from the wellhead to a natural gas processing facility or an interconnection with a larger pipeline.[81] A gathering system may include field compressors to move the gas to the pipeline or the processing plant. Field compressors are machines "driven by an internal combustion engine or turbine that creates pressure to 'push' the gas through the lines."[82] In some cases, the natural gas may be processed

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[80] NYSDEC, p. 5-85.
[81] Penn State Cooperative Extension. *Negotiating Pipeline Rights-of-Way in Pennsylvania*. The Pennsylvania State University, 2010.
[82] American Gas Association. "How Does the Natural Gas Delivery System Work?" Retrieved March 1, 2012 from http://www.aga.org/Kc/aboutnaturalgas/consumerinfo/Pages/NGDeliverySystem.aspx.

in the gathering system at a processing facility.[83] Natural gas must be processed to eliminate other hydrocarbons, water, sand and impurities that occur naturally with the natural gas. In some cases hydrocarbons, such as butane and propane, can be sold separately from the natural gas. There are no natural gas processing plants in North Carolina. If shale gas development occurred on a large scale in North Carolina, it is likely that a gas processing plant could be developed here.

From the gathering system, the natural gas moves through the transmission system. Transmission pipelines are wide diameter (20-48 inches), long-distance pipelines that move natural gas from producing regions to areas where gas is used. These pipelines are either interstate or intrastate. Interstate pipelines carry natural gas across state boundaries, while intrastate pipelines transport gas within a state.

Natural gas is highly pressurized as it travels through pipelines. To ensure natural gas remains pressurized, it is compressed periodically along the pipe at compressor stations. Compressor stations are located about "every 50 to 60 miles along each pipeline to boost the pressure that is lost through the friction of the natural gas moving through the steel pipe."[84] Generally, internal combustion engines provide the power to run compressors. These engines are fired using raw or processed natural gas. Compressor stations may also separate natural gas from hydrocarbons or water that naturally occurs with the gas. Bradford County officials told DENR staff that eventually there would be one compressor station for every 50 wells or every 10 well pads.[85]

When the natural gas in a pipeline reaches a gas utility, it normally passes through a gate station that reduces the pressure in the line to distribution levels, adds an odorant to the gas so consumers can smell gas leaks, and measures the amount of gas being received by the utility.[86] From the gate station, natural gas moves into distribution lines. The gas utility can control the pressure in the distribution lines. From distribution lines, natural gas enters service lines, and service lines deliver gas to pipes in homes and businesses.[87]

North Carolina does not currently produce natural gas and "the majority of North Carolina's natural gas is supplied by the Transcontinental Gas Pipeline Co. as the pipeline traverses the State en route from the Gulf Coast to major population centers in the Northeast."[88] Because of this, there are currently no gathering lines in North Carolina. If shale gas development occurs in North Carolina, a new web of gathering lines and additional transmission lines would have to be developed to carry the gas to markets. Bradford County officials told DENR staff that so far, "600 to 700 miles of pipeline" had been installed in Bradford County,[89] an area of 1,147 square

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[83] Ibid.
[84] Ibid.
[85] Personal communication, February 2, 2012.
[86] American Gas Association.
[87] Ibid.
[88] U.S. Energy Information Administration. "North Carolina." Retrieved March 1, 2012 from http://www.eia.gov/state/state-energy-profiles-analysis.cfm?sid=NC.
[89] Personal communication, February 2, 2012.

miles and home to 62,622 people as of the 2010 Census estimate.[90] A total of 1,734 well permits have been issued for Bradford County as of July 15, 2011.[91]

Regulation of natural gas transportation systems

While the development of new pipelines would create additional jobs and have other positive economic impacts, it would also create safety concerns and disturb large amounts of surface area. The Federal Energy Regulatory Commission (FERC) regulates interstate pipelines and "is responsible for authorizing the siting, construction, and operation of interstate natural gas pipelines."[92] As part of this process,

> "Virtually all applications to the FERC for interstate natural gas projects require some level of coordination with one or more federal agencies to satisfy the FERC's requirements for environmental review under the National Environmental Policy Act (NEPA), the Endangered Species Act, the National Historic Preservation Act, and the Magnuson-Stevens Act."[93]

Intrastate pipelines are regulated by states rather than FERC. Transmission lines may be regulated by a state public utilities commission, as is the case in North Carolina. However, in some cases, gathering lines may not be regulated at all. Pennsylvania only recently adopted legislation that grants the Public Utility Commission (PUC) more control over the safety of gathering lines. On Dec. 22, 2011, Gov. Tom Corbett signed Pennsylvania's Gas and Hazardous Liquids Pipelines Act (called the Pipeline Act), which expands the PUC's "authority to enforce federal pipeline safety laws as they relate to gas and hazardous liquids pipeline equipment and facilities," including gathering lines. Under the Pipeline Act, the PUC "will develop a registry and conduct safety inspections of the lines for all 'pipeline operators' in the state. The Commission also will identify and track the development of pipelines in less populated areas that transport gas from unconventional gas wells." The Pipeline Act is effective as of February 20, 2012.[94]

Pennsylvania's new law does not apply to pipelines in the most rural areas of the state where shale gas drilling is common, however, because the federal laws do not apply in rural areas with low-density populations.[95]

Since gathering lines are not regulated as a utility in Pennsylvania and are considered private lines, Bradford County officials told DENR staff that the local planning department went to individual gas operators to ask where the company was constructing pipelines.

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[90] U.S. Census Bureau. "Bradford County, Pennsylvania." *State and County QuickFacts*. Retrieved March 1, 2012 from http://quickfacts.census.gov/qfd/states/42/42015.html.

[91] Lovegreen, 2012.

[92] Federal Energy Regulatory Commission. "Processes for the Environmental and Historic Preservation Review of Proposed Interstate Natural Gas Facilities." May 29, 2003. Retrieved March 1, 2012 from http://www.ferc.gov/industries/gas/enviro/gasprocess.pdf.

[93] Federal Energy Regulatory Commission, 2003.

[94] Pennsylvania Public Utility Commission. "Act 127 Information." Retrieved March 1, 2012 from http://www.puc.state.pa.us/naturalgas/Act_127_Info.aspx.

[95] Tice, Dale A. "Pipeline Regulation in Pennsylvania." *Marcellus Shale Law Monitor*. December 29, 2011. Retrieved March 1, 2012 from http://www.marcellusshalelawmonitor.com/marcellus-development/pipeline-regulation-in-pennsylvania/.

One of the potential impacts of gathering lines as private, relatively unregulated lines is that each gas operator develops its own gathering lines. In some states, such as Pennsylvania, gathering lines are not subject to eminent domain, and "the pipeline operator must negotiate easements with each individual landowner along the route."[96] This may occur even though gas is being transported along similar routes, creating multiple impacts on the environment and the community where a single, slightly larger line may have served the same purpose (and have saved gas operators money). Forests may be cleared to construct the pipelines, which can increase forest edges. The impacts of forest edges are discussed in Section 4.G of this report.

In North Carolina, the existing interstate and intrastate transmission pipelines in North Carolina are regulated by the North Carolina Utilities Commission (NCUC). NCUC conducts inspections and monitoring of all the natural gas pipeline systems operating in North Carolina. In addition, NCUC considers environmental and social impacts as part of its process of issuing Certificates of Convenience. The power of eminent domain is given to these types of pipelines. According to the NCUC, it is not known what, if any, regulatory authority would apply to gathering lines.[97]

Figure 3-12. Construction of Underground Pipeline

Photo Credit: Mike Lovegreen

[96] Penn State Cooperative Extension, 2010.
[97] Personal communication, February 17, 2012.

D. Wastewater treatment

The potential additional domestic wastewater load from an influx of workers and supporting services associated with increased gas drilling and production cannot be projected until the economic impact analysis is completed. However, given the relatively small size of North Carolina's shale deposits compared to those in other states, it is not anticipated that managing the additional domestic wastewater load will present a significant challenge.

Section 4 – Potential environmental and health impacts

A. Constituents and contaminants associated with hydraulic fracturing

The use of chemicals in hydraulic fracturing

The hydraulic fracturing of a natural gas well involves injecting a mixture of proppant and fluids into the wellbore at high pressure, creating fractures in the rock. The proppant, which is often sand, holds the fractures open. These fractures become pathways for natural gas to flow towards the wellbore, increasing the rate at which natural gas can be extracted. Hydraulic fracturing creates permeability within the shale formation, allowing the well to produce a significant amount of natural gas.

Different types of hydraulic fracturing fluids can be used, but the two most common are slickwater fracturing and nitrogen foam fracturing. Slickwater fracturing (named for its ability to reduce friction, thus reducing the pressure needed to pump the fluid into the wellbore), is primarily water. Nitrogen foam fracturing uses nitrogen gas and less water than slickwater fracturing but is less common than slickwater fracturing. At this time it is unknown whether slickwater fracturing or nitrogen foam fracturing would prove more productive in North Carolina. As slickwater fracturing is the more commonly used method, it is assumed for the purposes of this report that slickwater fracturing would be used in the development of shale gas in North Carolina.

The fluid used for slickwater fracturing is typically 98 to 99.5 percent water and sand. As part of its draft *Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program*, the New York State Department of Environmental Conservation (NYSDEC) and its consultants studied the compositions by weight of a sample of fracturing fluid from the Fayetteville Shale and one from the Marcellus Shale. NYSDEC found that between approximately 84 – 90 percent of the fracturing fluid is water, and between 8 – 15 percent is sand.[98]

In addition to water and sand or other proppants, a number of chemical additives are used to condition the water, each with its own engineered purpose. Additives may be used to thicken or thin the fluid, prevent corrosion of the well casing, kill bacteria or perform other tasks. The mixture of constituents used in the hydraulic fracturing fluid varies depending on the drilling company, specific characteristics of the geologic basin (such as depth, temperature, thermal maturity and structural characteristics), and the well operator's objectives.[99]

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[98] New York State Department of Environmental Conservation (NYSDEC). *Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program,* p. 5-51. Completed September 7, 2011. Retrieved September 7, 2011 from http://www.dec.ny.gov/energy/75370.html.

[99] NYSDEC, p. 5-39.

It is important to note that because of the inherent variability in the composition of hydraulic fracturing fluids, the fluids used in shale gas basins across the United States as discussed in this section are not necessarily indicative of the exact composition of constituents that could be used in North Carolina. However, it is likely that some of these constituents would be used in North Carolina.

While there are hundreds of chemicals from which operators may choose to use in any given hydraulic fracturing mixture (usually six to 12 per fracturing job), FracFocus, the chemical disclosure registry that is a project of the Groundwater Protection Council and the Interstate Oil and Gas Compact Commission, notes that "there are a limited number [of chemicals] which are routinely used in hydraulic fracturing." The website provides a list of 59 chemicals that are "used the most often." Other sources provide longer lists of chemicals that could potentially be used in any given operation. In 2011, the Committee on Energy and Commerce of the United States House of Representatives completed a study on chemicals used in hydraulic fracturing operations. The Committee asked 14 leading oil and gas service companies to disclose the types and volumes of hydraulic fracturing products used in hydraulic fracturing fluids between 2005 and 2009.[100] The Committee found that during that time period, the 14 oil and gas service companies used more than 2,500 hydraulic fracturing products containing 750 chemicals and other components. This totaled 780 million gallons of additives, not including the water that is added to hydraulic fracturing fluids at the well site before injection.

NYSDEC collected information on additives proposed for use in fracturing in New York from 15 chemical suppliers and six service companies.[101] This information included material safety data sheets and "product composition disclosures consisting of chemical constituent names and their associated Chemical Abstract Service (CAS) Numbers, as well as chemical constituent percent by weight information." NYSDEC obtained information for 235 products, which included 322 unique chemicals with CAS numbers and at least another 21 compounds that have no disclosed CAS number because they are mixtures. The list of chemical constituents and CAS numbers that NYSDEC extracted from the product composition disclosures and MSDSs submitted to NYSDEC begins on page 5-55 of NYSDEC's *Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program.*

Classes of chemicals used

Although there are hundreds of chemicals an oil and gas operator may use when preparing to hydraulically fracture a well, a smaller number of additives (such as six to 12) are used on any single well. This is because the chemical additives fall into certain categories, and only one product from each category is used in any given hydraulic fracturing fluid. In addition, not every category may be used in any given hydraulic fracturing operation.[102] The following table shows

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[100] United States. Cong. House. Committee on Energy and Commerce. "Chemicals Used in Hydraulic Fracturing." April 2011. Retrieved January 5, 2012 from http://democrats.energycommerce.house.gov/sites/default/files/documents/Hydraulic%20Fracturing%20Report%204.18.11.pdf.

[101] NYSDEC, pp. 5-40 – 5-41.

[102] NYSDEC, pp. 5-49 – 5-51.

the categories, purposes and examples of additives reported to NYSDEC as proposed for use in hydraulic fracturing wells in New York State. The categories listed are similar to additives shown on FracFocus (www.fracfocus.org), with the exception of solvents, a category that does not appear on the FracFocus list. The categories listed in Table 4-1 are also similar to additives listed in the Department of Energy's *Modern Shale Gas Development in the United States: A Primer*.

Table 4-1. Categories and Purposes of Additives Proposed for Use in New York State[103]

Additive Type	**Description of Purpose**	**Examples of Chemicals**
Acids	Removes cement and drilling mud from casing perforations prior to injecting other fracturing fluids, providing an accessible path to the shale formation	Hydrochloric acid (HCl, 3% to 28%) or muriatic acid
Bactericide/Biocide/ Antibacterial Agent	Inhibits growth of organisms that could produce gases (particularly hydrogen sulfide) that could contaminate methane gas. Also prevents the growth of bacteria which can reduce the ability of the fluid to carry proppant into the fractures.	Gluteraldehyde; 2,2-dibromo-3-nitrilopropionamide
Breaker	Reduces the viscosity of the fluid in order to release proppant into fractures and enhance the recovery of the fracturing fluid	Peroxydisulfates
Buffer/pH Adjusting Agent	Adjusts and controls the pH of the fluid in order to maximize the effectiveness of other additives such as crosslinkers	Sodium or potassium carbonate; acetic acid
Clay stabilizers/Control/KCI	Prevents clays from swelling or shifting, which block pore spaces, reducing permeability	Salts such as potassium chloride (KCI) or tetramethyl ammonium chloride
Corrosion inhibitors (including Oxygen Scavengers)	Reduces rust formation on steel tubing, well casings, tools, and tanks (used only in fracturing fluids that contain acid).	Methanol; ammonium bisulfate for oxygen scavengers
Crosslinker	Increases fluid viscosity using phosphate esters combined with metals. The metals are referred to as crosslinking agents. The increased fracturing fluid viscosity allows the fluid to carry more proppant into the fractures.	Potassium hydroxide; borate salts
Friction reducers	Allows fracture fluids to be injected at optimum rates and pressures by minimizing friction.	Sodium acrylate-acrylamide copolymer; polyacrylamde (PAM); petroleum distillates
Gelling agents	Increases fracturing fluid viscosity, allowing the fluid to carry more proppant	Guar gum; petroleum distillates
Iron control	Prevents the precipitation of metal oxides which could plug off the formation.	Citric acid
Proppants	Hold open the fractures to allow gas to flow more freely to the well bore	Sand, sintered bauxite, zirconium oxide, ceramic beads
Scale inhibitors	Prevents the precipitation of carbonates and sulfates (calcium carbonate, calcium sulfate, barium sulfate) which could plug off the formation.	Ammonium chloride; ethylene glycol
Solvent	Additive which is soluble in oil, water and acid-based treatment fluids which is used to control the wettability of contact surfaces or to prevent or break emulsions.	Various aromatic hydrocarbons
Surfactants	Reduces fracturing fluid surface tension, which aids in fluid recovery	Methanol; isopropanol; ethoxylated alcohol

[103] This table is based on the table in NYSDEC, p. 5-50 and on a table on page 63 of the Department of Energy's *Modern Shale Gas Development in the United States: A Primer* (written by the Ground Water Protection Council and published in April 2009) and from a table at http://fracfocus.org/chemical-use/what-chemicals-are-used.

The Committee on Energy and Commerce of the U.S. House of Representatives found that the most widely used chemical in hydraulic fracturing was methanol, a hazardous air pollutant that is on EPA's list of contaminants that are currently not subject to any proposed or promulgated national primary drinking water regulations, that are known or anticipated to occur in public water systems, and which may require regulation under the Safe Drinking Water Act (SDWA). Methanol was used in 342 hydraulic fracturing products. Other chemicals that were the most widely used were isopropyl alcohol, ethylene glycol and crystalline silica.

Another commonly used chemical is 2-butoxyethanol (2-BE), which is used by hydraulic fracturing companies as a surfactant. The Committee writes, "According to EPA scientists, 2-BE is easily absorbed and rapidly distributed in humans following inhalation, ingestion, or dermal exposure. Studies have shown that exposure to 2-BE can cause hemolysis (destruction of red blood cells) and damage to the spleen, liver, and bone marrow."[104]

Use of proprietary chemicals

Although much is known about the chemicals used in hydraulic fracturing, this knowledge remains imperfect. Many companies were unable to provide the Committee on Energy and Commerce with a complete chemical makeup for their hydraulic fracturing fluids. The Committee found that "Between 2005 and 2009, the companies used 94 million gallons of 279 products that contained at least one chemical or component that the manufacturers deemed proprietary or a trade secret."[105] In some cases, oil and gas companies purchased these products off the shelf from chemical suppliers, and simply did not know what chemicals they were using. In the event of a spill, lack of knowledge about the chemical makeup could pose challenges for emergency responders.

The use of diesel in hydraulic fracturing fluids

Diesel fuel has been used as an additive in hydraulic fracturing fluids and according to some sources, companies continue to use diesel fuel. The use of diesel is a concern because it contains toxic constituents, including the BTEX compounds benzene, toluene, ethylbenzene, and xylenes. Benzene is a human carcinogen, while chronic exposure to toluene, ethylbenzene, or xylenes can damage the central nervous system, liver and kidneys.[106]

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[104] United States. Cong. House. Committee on Energy and Commerce. "Chemicals Used in Hydraulic Fracturing." April 2011. Retrieved January 5, 2012 from http://democrats.energycommerce.house.gov/sites/default/files/documents/Hydraulic%20Fracturing%20Report%204.18.11.pdf, p. 7.

[105] Ibid, p. 2.

[106] United States. Cong. House. Committee on Energy and Commerce. "Waxman, Markey, and DeGette Investigation Finds Continued Use of Diesel in Hydraulic Fracturing Fluids." January 31, 2011. Retrieved January 5, 2012 from http://democrats.energycommerce.house.gov/index.php?q=news/waxman-markey-and-degette-investigation-finds-continued-use-of-diesel-in-hydraulic-fracturing-f.

In 2003, the EPA entered into a memorandum of agreement with the three largest providers of hydraulic fracturing fluids "to eliminate the use of diesel fuel in hydraulic fracturing fluids injected into coalbed methane production wells in underground sources of drinking water."[107]

Unlike other additives for hydraulic fracturing, the use of diesel fuel as a hydraulic fracturing fluid is regulated by the Safe Drinking Water Act. According to the EPA, diesel remains regulated by SDWA (while other hydraulic fracturing fluids are excluded) "because of concern about the risks to drinking water from diesel fuel."[108] This means that any operator who uses diesel as a hydraulic fracturing additive should receive authorization from the Underground Injection Control program to do so.

Because of the lack of an exception under SDWA for diesel and the memorandum of agreement between EPA and three major hydraulic fracturing operators, some believe that diesel is no longer used as a hydraulic fracturing additive or that its use has substantially decreased. EPA staff told the U.S. House of Representatives Committee on Energy and Commerce that "the agency assumed that the MOA had eliminated most diesel use."[109] In February 2010, the Committee began an investigation into hydraulic fracturing, collecting information from 14 oil and gas service companies who voluntarily provided data, including material safety data sheets, on the volume of diesel fuel and other additives they had used from 2005 to 2009. The Committee found that 12 of the 14 hydraulic fracturing companies injected more than 30 million gallons of diesel fuel or hydraulic fracturing fluids containing diesel fuel in wells in 19 states. In addition, the Committee found that the BTEX compounds (benzene, toluene, ethyl benzene, xylene) were in 60 hydraulic fracturing products in use between 2005 and 2009 and were used in 11.4 million gallons of hydraulic fracturing fluids.[110]

To assess whether these companies obtained the required Underground Injection Control permit to use diesel fuel as a hydraulic fracturing component under the SDWA, the Committee contacted state agencies and regional offices in the 19 states where diesel fuel was used as a component of hydraulic fracturing fluids. Every state and regional EPA office contacted stated that they had never issued a UIC permit for use of diesel fuel in fracturing or received an application for a UIC permit to authorize its use. Some of the state regulators who were

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[107] United States Environmental Protection Agency. "A Memorandum of Agreement between the United States Environmental Protection Agency and BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation." Retrieved February 26, 2012 from http://s3.amazonaws.com/propublica/assets/natural_gas/diesel_agreement_031212.pdf.

[108] United States Environmental Protection Agency. "Natural Gas Extraction: Hydraulic Fracturing." Retrieved January 23, 2012 from http://www.epa.gov/hydraulicfracture/#diesel.

[109] United States. Cong. House. Committee on Energy and Commerce. "Waxman, Markey, and DeGette Investigation Finds Continued Use of Diesel in Hydraulic Fracturing Fluids." January 31, 2011. Retrieved January 5, 2012 from http://democrats.energycommerce.house.gov/index.php?q=news/waxman-markey-and-degette-investigation-finds-continued-use-of-diesel-in-hydraulic-fracturing-f.

[110] United States. Cong. House. Committee on Energy and Commerce. "Chemicals Used in Hydraulic Fracturing." April 2011. Retrieved January 5, 2012 from http://democrats.energycommerce.house.gov/sites/default/files/documents/Hydraulic%20Fracturing%20Report%204.18.11.pdf p. 10.

contacted expressed doubt that diesel fuel had been used in hydraulic fracturing.[111] EPA is currently developing permitting guidance for hydraulic fracturing using diesel fuels under SDWA Underground Injection Control Class II regulations. N.C. General Statute 143-214.2(b) prohibits the use of wells for waste disposal.

Health information related to hydraulic fracturing fluids

Fracturing fluids can pose concerns to public health and the environment; however, exposure to hydraulic fracturing additives should occur only in the case of an accident, spill or other non-routine incident. Such non-routine incidents could occur either while transporting additives to the well pad, during well pad operations or while transporting wastewater. After chemicals have been injected for hydraulic fracturing, a certain amount of the fluid returns to the surface as "flowback." This wastewater is stored in pits or tanks at the surface; absent sufficient safeguards, this wastewater can spill or overflow following heavy rainfall. If these chemicals are not properly disposed of or if an accident occurs in which fluids spill onto the ground or into surface waters, the fracturing fluid could pose threats to human health, the environment and to the health of livestock or wildlife. In the event of improper cementing of well casings, these chemicals could contaminate drinking water supplies. If a spill or other release occurred, more specific information about the chemicals involved would be required in order to assess the health impact.

The New York State Department of Environmental Conservation (NYSDEC) requested assistance from the New York State Department of Health (NYSDOH) in identifying potential exposure pathways and constituents of concern associated with hydraulic fracturing. NYSDOH assessed the health concerns by examining chemicals grouped into categories according to their chemical structure (or function in the case of microbiocides). Based on this assessment, NYSDEC concludes,

> "Chemicals in products proposed for use in high-volume hydraulic fracturing include some that, based mainly on occupational studies or high-level exposures in laboratory animals, have been shown to cause effects such as carcinogenicity, mutagenicity, reproductive toxicity, neurotoxicity or organ damage. This information only indicates the types of toxic effects these chemicals can cause under certain circumstances but does not mean that use of these chemicals would cause exposure in every case or that exposure would cause those effects in every case. Whether or not people actually experience a toxic effect from a chemical depends on whether or not they experience any exposure to the chemical along with many other factors including, among others, the amount, timing, duration and route of exposure and individual characteristics that can contribute to differences in susceptibility."[112]

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[111] United States. Cong. House. Committee on Energy and Commerce. "Waxman, Markey, and DeGette Investigation Finds Continued Use of Diesel in Hydraulic Fracturing Fluids." January 31, 2011.
[112] NYSDEC, p. 5-79.

Some of the chemicals used in hydraulic fracturing fluids are relatively harmless, such as salt and citric acid. Others are known and possible human carcinogens and toxicants that are regulated under the Safe Drinking Water Act for their risks to human health, under the Clean Water Act for their risks and toxic effects to human health, fish and wildlife, or listed as hazardous air pollutants under the Clean Air Act. The oil and gas service companies that reported to the Committee on Energy and Commerce used products containing 29 chemicals, in a total of 652 different products for hydraulic fracturing, that are "(1) known or possible human carcinogens, (2) regulated under the Safe Drinking Water Act for their risks to human health, or (3) listed as hazardous air pollutants under the Clean Air Act."[113]

Many of the chemicals used in hydraulic fracturing fluids are also regulated under the Clean Water Act for their toxic effects to human health and aquatic life. Some of the chemicals used in the hydraulic fracturing process have North Carolina Surface Water and Groundwater Quality Standards; however, many do not. If these chemicals are released to North Carolina waters, defensible and enforceable state water quality standards are needed to address potential adverse effects to public health and the environment.

Carcinogens

The Committee found that between 2005 and 2009, hydraulic fracturing operators used 95 products containing 13 different known, probable, or possible carcinogens.[114] These included naphthalene, benzene, and acrylamide. In the Committee's study, companies injected 10.2 million gallons of fracturing additives containing at least one carcinogen. Many of these chemicals also have adverse non-cancer human health effects, such as impacts to the kidney, liver and lungs.

Safe Drinking Water Act registered chemicals

While most underground injections of chemicals are regulated under the Safe Drinking Water Act (SDWA), Congress modified the law in 2005 to exclude "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" from the Act. Unless diesel is used in the hydraulic fracturing process, the permanent underground injection of chemicals used for hydraulic fracturing is not regulated by the EPA.[115] This exemption only applies to injection for purposes of fracturing; underground injection of drilling wastes continues to require a Safe Drinking Water Act permit.

The Safe Drinking Water Act requires that Class II injection wells be permitted under the Underground Injection Control (UIC) Program, which is implemented by the EPA or by states that have been granted primacy by EPA to implement the program. At present, North Carolina has primacy for all classes of injection wells, but state law prohibits the use of Class II and other deep waste injection wells.

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[113] U.S. House of Representatives Committee on Energy and Commerce, p. 8.
[114] Ibid, p. 9.
[115] Ibid.

The disposal of fluids that are recovered and disposed of as wastewater from the hydraulic fracturing process are also covered under the Clean Water Act. Wastewater may be temporarily stored in tanks or pits at the well site, where spills are possible. To dispose of the wastewater, operators may inject it into underground injection wells regulated under the Safe Drinking Water Act as described above, transport it to wastewater treatment facilities regulated under the Clean Water Act, or dispose of it through land application methods regulated by states.

There are concerns about the ability of wastewater treatment plants to adequately treat this type of wastewater. In 2011, Gov. Tom Corbett and the Pennsylvania Department of Environmental Protection asked natural gas drillers to stop sending wastewater from drilling operations to the 15 publicly owned water treatment plants that were accepting it at the time because of concern over the elevated levels of bromide being discharged to rivers in the wastewater effluent. Although bromide is non-toxic, when bromide mixed with chlorine for disinfection at a water treatment facilities becomes "a combination of potentially unsafe compounds called Total Trihalomethanes."[116]

Hazardous Air Pollutants

The Clean Air Act requires EPA to control the emissions of 187 hazardous air pollutants. Hazardous air pollutants are pollutants that are known or are suspected to cause cancer or other serious health effects, such as reproductive problems, birth defects or developmental, respiratory and other health problems. Hazardous air pollutants can also cause adverse environmental effects. In addition to exposure through breathing, hazardous air pollutants can also be deposited onto soils or surface waters and taken up by plants or ingested by animals. Humans can then be exposed to these toxic pollutants by eating exposed plants or animals. Animals may also experience health problems if exposed to sufficient quantities of air toxics over time.[117]

EPA regulates emissions of hazardous air pollutants through Maximum Achievable Control Technology (MACT) standards. The state of North Carolina issues federal Clean Air Act permits that include MACT standards for any federally regulated source of hazardous air emissions in the state. North Carolina also has a state health-based program to regulate emissions of toxic air pollutants. The state program, which has been in effect since May 1, 1990, regulates 105 toxic air pollutants (TAPs). Most of the TAPs are also considered HAPs by the EPA. The state program reaches some sources of toxic air emissions that are not regulated under the federal program.

According to the survey of chemicals used in hydraulic fracturing operations by the U.S. House Energy and Commerce Committee, companies used 595 products containing 24 different hazardous air pollutants between 2005 and 2009.[118] As examples, the U.S. House Energy and Commerce Committee points to hydrogen fluoride, lead and methanol. Hydrogen fluoride can

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[116] Gresh, Katy. "DEP Calls on Natural Gas Drillers to Stop Giving Treatment Facilities Wastewater." Pennsylvania Department of Environmental Protection. April 19, 2011. Retrieved February 26, 2012 from http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=17071&typeid=1.

[117] EPA. http://www.epa.gov/oar/toxicair/newtoxics.html. Retrieved January 18, 2012.

[118] U.S. House of Representatives Committee on Energy and Commerce, 2011.

cause severe and sometimes delayed health effects due to deep tissue penetration. Lead is particularly harmful to children's neurological development but can also cause health problems in adults. The EPA reports that exposure to small amounts of methanol can cause headaches, incoordination, sleep disorders, gastrointestinal problems, and optic nerve damage.[119]

Chemicals used aboveground

In addition to the chemicals that are pumped into well bores to enhance hydraulic fracturing, drilling for natural gas involves the use of a number of chemicals aboveground. These chemicals could potentially pose a threat to public health or the environment if they are spilled either at the drilling site or in transit. Drilling rigs require power to drill and case wellbores. Typically, in the Marcellus Shale, this power would be provided by transportable diesel engines.[120] During hydraulic fracturing, "To inject the required water volume and achieve the necessary pressure, up to 20 diesel-pumper trucks operating simultaneously are necessary" for a period of two to five days per well.[121] Diesel is stored on the well pad for this purpose and "The diesel tank fueling storage may be larger than 10,000 gallons in capacity and may be in one location on a multi-well pad for the length of time required to drill all of the wells on the pad."[122]

In addition to use in hydraulic fracturing operations, hazardous air pollutants also originate from mobile sources, such as the trucks that are used by gas drilling companies. The potential impacts from air emissions are discussed in Section 4.F of this report.

Regulation of hydraulic fracturing chemical disclosure

Some states regulate the disclosure of hydraulic fracturing fluids and their chemical additives. The level of disclosure required varies by state. So far, Colorado is the only state to require the names and concentrations of all individual chemicals used.[123] Some states merely require the compilation of material safety data sheets (MSDSs) for additives. The Occupational Safety and Health Administration (OSHA) requires chemical manufacturers to create an MSDS for every product they sell to communicate potential health and safety hazards to employees and employers. The MSDS must list all hazardous ingredients if they comprise at least 1% of the product; for carcinogens, the reporting threshold is 0.1%.[124] Chemical manufacturers do not have to disclose trade secret information on MSDSs, which allows many additives used in hydraulic fracturing to be withheld. Some states require that operators also disclose Chemical Abstract Service (CAS) registry numbers, unique numerical identifiers for chemicals.

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[119] United States Environmental Protection Agency. "Chemicals in the Environment: Methanol (CAS No. 67-56-1)." August 1994. Retrieved February 26, 2012 from http://www.epa.gov/chemfact/f_methan.txt.
[120] NYSDEC, p. 6-196.
[121] NYSDEC, p. 6-296.
[122] NYSDEC, p. 7-33.
[123] Groeger, Lena. "Federal Rules to Disclose Fracking Chemicals Could Come with Exceptions." ProPublica. February 16, 2012. Retrieved February 27, 2012 from http://www.propublica.org/article/federal-rules-to-disclose-fracking-chemicals-could-come-with-exceptions.
[124] U.S. House of Representatives Committee on Energy and Commerce, 2011.

Many states allow reporting of chemical information to be made to FracFocus (www.fracfocus.org), a website managed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission that serves as a type of clearinghouse for this information. The site was created “to provide the public access to reported chemicals for hydraulic fracturing,” but also includes “objective information on hydraulic fracturing, the chemicals used, the purposes they serve and the means by which groundwater is protected.” Although FracFocus provides a convenient location for chemical disclosure information from several states, it does have some limitations. Most notably, information is provided via .pdf documents for each well and is not in a database or spreadsheet format that could be used to analyze data across counties, states or other geographies. GWPC plans to release a new version of FracFocus in late 2012 that will include the capability to provide data to states, though not the general public, in spreadsheet format.[125]

Arkansas requires companies to disclose all fracturing fluids, additives, chemical constituents and CAS numbers to the Arkansas Oil and Gas Commission, with the exception of chemicals that are considered trade secrets.[126] Information on concentrations used is not required, but operators report the percent by volume of each product used. The information is disclosed to the state and must be provided to health care professionals who require it. The chemical family is disclosed to the public using the state website. The information is due before hydraulic fracturing begins and updates must be submitted after hydraulic fracturing.[127] The rule became effective on Jan. 15, 2011.[128]

Colorado requires drillers to disclose all the chemicals used in hydraulic fracturing, as well as the concentrations of each chemical and the CAS numbers. Certain chemical names can be withheld as trade secrets. Operators are also required to disclose these chemicals to the public using the FracFocus website and directly to the Colorado Oil & Gas Conservation Commission. Chemicals, including those considered trade secrets, must also be disclosed to health professionals in an emergency when disclosure is necessary. The requirements will be effective April 1, 2012.[129] The trade secret provisions of Colorado’s rule are slightly different than in other states. Whereas in other states, companies can determine which chemicals are trade secrets or state regulators or the governor sign off on trade secret requests, “In Colorado, companies will be required to sign a legally-binding form to declare a chemical proprietary. Drillers who lie could be charged with perjury.”[130] The information must be posted to FracFocus

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[125] Mike Nickolaus, GWPC. Personal communication, March 12, 2012.

[126] Louisiana Department of Natural Resources. “Comparison of State Hydraulic Fracturing Chemical Disclosure Regulations.” December 30, 2011. Retrieved February 27, 2012 from http://dnr.louisiana.gov/index.cfm?md=pagebuilder&tmp=home&pid=888.

[127] ProPublica. “Fracking Chemical Disclosure Rules.” February 16, 2012. Retrieved February 27, 2012 from http://www.propublica.org/special/fracking-chemical-disclosure-rules.

[128] Louisiana Department of Natural Resources, 2011.

[129] Ibid.

[130] Detrow, Scott. “Colorado Approves Fracking Disclosure Regulations.” StateImpact. December 14, 2011. Retrieved February 27, 2012 from http://stateimpact.npr.org/pennsylvania/2011/12/14/colorado-approves-fracking-disclosure-regulations/.

within 60 days of hydraulic fracturing activity.[131]

Louisiana requires operators to disclose additives in products subject to Occupational Safety and Health Administration (OSHA) Hazard Communication requirements (29 CFR 1910.1200), which requires MSDSs for chemicals considered hazardous to worker safety. For these additives, Louisiana requires the disclosure of the chemical names and concentrations of the chemicals. Operators can either report disclosure information to the Office of Conservation or post it to the FracFocus website within 20 days of well completion.[132] According to the Department of Natural Resources, "The Louisiana regulation has no effect on rules or laws mandating disclosure of trade secret information to health care providers." The rules are effective as of Oct. 20, 2011.[133]

Michigan requires that material safety data sheets be filed for hazardous chemicals and matched with the products into which they go. Operators disclose a range of concentrations, not the exact concentration. Proprietary information is not disclosed to regulators or the public. MSDSs are posted on the state website and must be provided within 60 days of drilling completion.[134]

Montana requires operators to disclose the names and CAS numbers of chemicals that are not deemed trade secrets to the Montana Oil and Gas Board or to the FracFocus website. Operators provide the chemical family and the maximum concentration of chemicals, not the actual concentration. Proprietary chemicals, as determined by the well operator, can be withheld but must be disclosed to health care professionals in an emergency. MSDSs are required before hydraulic fracturing begins and after it is complete. Disclosure must be made before hydraulic fracturing begins and after it is completed.[135] The requirements are effective for all hydraulic fracturing performed after Aug. 27, 2011.[136]

Ohio requires material safety data sheets, which list the products' chemical components and CAS numbers. Concentrations of chemicals are not disclosed. Proprietary information is not disclosed to regulators or the public. No specific requirements are in place for medical disclosure, but "a regulator from the Ohio Dept. of Natural Resources said he's confident the information would be provided to health care professionals in an emergency."[137] The information is required 60 days after drilling is complete and is posted on the state website.[138]

New Mexico recently adopted regulations that require operators to disclose all additives used in hydraulic fracturing fluids and the names and concentrations of chemicals that are subject to OSHA Hazard Communication requirements. Operators do not have to disclose trade secret

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131 ProPublica. "Fracking Chemical Disclosure Rules." February 16, 2012.
132 Ibid.
133 Louisiana Department of Natural Resources, 2011.
134 ProPublica. "Fracking Chemical Disclosure Rules." February 16, 2012.
135 Ibid.
136 Louisiana Department of Natural Resources, 2011.
137 ProPublica. "Fracking Chemical Disclosure Rules." February 16, 2012.
138 Ibid.

information. Disclosure can be made by reporting to the Oil Conservation Division. The rule is effective as of Feb. 15, 2012.[139]

North Dakota has passed new rules related to hydraulic fracturing that will become effective on April 1, 2012. The revised regulation requires the owner, operator or service company to post to FracFocus "all elements made viewable by the FracFocus website,"[140] which includes the total volume of water used at the well, the trade names of chemicals used, the supplier of each chemical, the purpose of each chemical, the ingredients, the chemical abstract service number, the maximum ingredient concentration in the additive, and the maximum ingredient concentration in the hydraulic fracturing fluid.[141]

Pennsylvania has a regulation requiring operators to disclose to the Pennsylvania Office of Oil and Gas Management the names of products and chemicals, without matching them with the products into which they go. Operators must also disclose the names and concentrations of chemicals subject to OSHA Hazard Communication requirements.[142] All chemical constituents must be provided by the operator if the department makes a request in writing.[143] The information is required within 30 days of well completion. It is not posted online but is available by request from the Department of Environmental Protection.[144] Trade secret information is protected. The requirements are effective as of Feb. 5, 2012.[145]

Texas recently revised its chemical disclosure rules. The revised rules require that service companies disclose to operators the names of products, chemicals that are not deemed trade secrets, and their CAS numbers. Only hazardous chemicals are matched with the products of which they are a component. The concentrations of chemical constituents are only required for chemicals subject to OSHA Hazard Communication requirements.[146] A listing of chemical ingredients used to hydraulically fracture a well that has been permitted by the Texas Railroad Commission on or after Feb. 1, 2012, must be uploaded to the FracFocus website. A supplier, service company or operator is not required to disclose trade secret information unless the Attorney General or court determines the information is not entitled to trade secret protection.[147]

Wyoming has a regulation requiring operators or service companies to disclose the names of products, chemicals and their CAS numbers. Operators must disclose product concentrations

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[139] Title 19, *New Mexico Administrative Code*, Chapter 15, Part 16.
[140] North Dakota Industrial Commission. "Order of the Commission." Case no. 15869, Order no. 18123. January 23, 2012. Retrieved February 27, 2012 from https://www.dmr.nd.gov/oilgas/or18123.pdf.
[141] This list of elements viewable on the FracFocus website was taken from the "Hydraulic Fracturing Fluid Product Component Information Disclosure" for the Dave 2H well in Bradford County, Pennsylvania, retrieved February 27, 2012 from http://www.hydraulicfracturingdisclosure.org/fracfocusfind/.
[142] ProPublica. "Fracking Chemical Disclosure Rules." February 16, 2012.
[143] Louisiana Department of Natural Resources, 2011.
[144] ProPublica. "Fracking Chemical Disclosure Rules." February 16, 2012.
[145] Ibid.
[146] ProPublica. "Fracking Chemical Disclosure Rules." February 16, 2012.
[147] Nye, Ramona. "Railroad Commissioners Adopt One of Nation's Most Comprehensive Hydraulic Fracturing Chemical Disclosure Requirements." Railroad Commission of Texas. December 13, 2011. Retrieved February 27, 2012 from http://www.rrc.state.tx.us/pressreleases/2011/121311.php.

but not the concentrations of individual chemical components to the supervisor of the Wyoming Oil and Gas Conservation Commission. The information is not made public.[148] Trade secret information is kept confidential according to the Wyoming Public Records Act. The requirements have been in effect since Aug. 17, 2010.[149]

The United States Bureau of Land Management (BLM) has developed draft regulations applicable to wells that are hydraulically fractured on federal land. The proposed rules would require the disclosure of the names of products, chemicals and CAS numbers. Concentrations of chemicals would be disclosed for some products. At this time the rules are still a draft, and it is unclear whether the information collected by BLM would be posted publicly.[150] BLM's proposed rules would also "compel companies to report the total volume of fracking fluid used, as well as how they intend to recover and dispose of it."[151]

Conclusions related to hydraulic fracturing additives

We recommend that the General Assembly require full disclosure of hydraulic fracturing chemicals and constituents to the state regulatory agency and to local government emergency response officials. We also recommend that the General Assembly should require the industry to disclose all hydraulic fracturing chemicals and constituents – except for information protected under North Carolina law as a trade secret – to the public through the FracFocus website or a state agency website.

The use of diesel fuel in fracturing fluid is a concern because it contains toxic constituents, including the BTEX compounds benzene, toluene, ethylbenzene, and xylenes. Benzene is a human carcinogen, while chronic exposure to toluene, ethylbenzene, or xylenes can damage the central nervous system, liver and kidneys. We recommend that its use as a hydraulic fracturing constituent be completely prohibited.

B. Hydrogeologic framework of the Triassic Basins

The areas of current interest for potential shale gas development are located within the Deep River Triassic Basin and Dan River Triassic Basin. The Triassic Basins are geologically distinct from the surrounding geologic belts in that they are filled with sedimentary rocks, meaning they have different hydrogeologic properties than the igneous and metamorphic bedrock that is found adjacent to them. The sedimentary rocks that occur in the basin include sandstone, shale, siltstone and conglomerate.

The sedimentary rocks in the Sanford sub-basin tend to have very low permeability due to the presence of fine-grained material commonly occurring within the spaces between the larger grains. There are no defined "aquifers" in the customary sense in the Sanford sub-basin, such as

[148] ProPublica. "Fracking Chemical Disclosure Rules." February 16, 2012.
[149] Louisiana Department of Natural Resources, 2011.
[150] ProPublica. "Fracking Chemical Disclosure Rules." February 16, 2012. Retrieved February 27, 2012 from http://www.propublica.org/special/fracking-chemical-disclosure-rules.
[151] Groeger, 2012.

those that occur in the Coastal Plain region of the state. Instead, most water supply wells in the Triassic Basins actually derive their water from fractures in the rock.

Numerous thin bodies of igneous rock intrude into the sedimentary rocks of the basin. These intrusions, of a rock known as diabase, are typically long, thin planar bodies ranging in thickness from less than a foot to tens of feet thick. Most often in the Triassic Basins, they occur as near-vertical dikes cutting across older sedimentary rocks. They may also occur as flat-lying sills, but this is much less common. The diabase intrusions are highly fractured, along with the sedimentary rocks immediately adjacent to them and are therefore capable of yielding sufficient quantities of water to support water supply wells. Groundwater can often flow freely for great distances along the edges of these diabase intrusions, but when the diabase intrusions are relatively thick they tend to restrict groundwater flow.

Most knowledge of groundwater conditions in the Triassic Basins comes from wells that have been drilled for water supply. Few studies of the hydrogeology of the Triassic Basins have been conducted. No groundwater monitoring stations have been constructed in the Triassic Basins of North Carolina. Because of this, our understanding of the hydrogeology of the Triassic Basins is limited to information that can be recovered from water supply wells, which typically only extend a few hundred feet deep.

Little relevant data is available on the overall background quality of groundwater in the Triassic Basins. A 1961 study by the U.S. Geological Survey and the N.C. Department of Water Resources (now the Division of Water Quality and Division of Water Resources within the Department of Environment and Natural Resources) reported sample results for three wells in the Deep River Basin in Lee County and noted that the groundwater in the Deep River Basin tended to be moderately hard to hard.[152]

In 2010, 960 groundwater samples collected from private wells in the 12 counties encompassing the Deep River and Dan River Triassic Basins were tested for chloride levels. [153] The Division of Water Quality does not have sufficiently reliable location data at this time to determine how many of these wells were within the Triassic Basins. Of the 960 samples analyzed for chloride, 10 samples (roughly 1 percent) had chloride concentrations of 250 milligrams per liter (mg/L) or greater, the threshold between fresh water and brackish or saline water. From this very coarse examination, it does not appear that shallow saline groundwater is common in the Triassic Basins. A more rigorous examination of existing groundwater quality in the Sanford Sub-basin is underway as part of an inventory being conducted by the United States Geological Survey (USGS) under contract to DENR.

The sample results described above, along with geological information suggesting that the Triassic Basin rocks were deposited in ancient lakes rather than in marine environments, indicate that groundwater at depths below existing water supply wells is not likely to be saline, although it may be hard. If these results accurately reflect characteristics of deep groundwater

[152]Schipf, Robert G. . *Geology and Ground-Water Resources of the Fayetteville Area.* North Carolina Department of Water Resources, 1961.

[153] State Public Health Laboratory, N.C. Department of Health and Human Services. Results of private drinking water well samples collected in 2010.Dataset provided to DWQ in March 2011.

in the Triassic Basins, the producing zones and hydraulically fractured intervals of any gas wells will be located in potential future water supplies.[154]

Available groundwater data from North Carolina's Triassic Basins stands in contrast to conditions in Pennsylvania, where the shale gas resource lies at depths of roughly 10,000 feet or more. The deepest water supply wells in that area are generally no more than 600 feet deep, and it is not uncommon to encounter highly saline groundwater at depths of 600 to 750 feet.[155] As a result, the gas-producing layer lies thousands of feet below groundwater likely to be used for drinking water supply. By contrast, water supply wells of up to 1,000 feet deep have been found in North Carolina's Triassic Basins, and the depth to which freshwater extends is unknown. Some of 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.

Well locations and groundwater use

Statewide, groundwater provides drinking water supply for 42 percent of North Carolinians either by private drinking water wells or public water systems.[156] Groundwater is also the most commonly used source of water for livestock and for irrigation of crops. In most of North Carolina, groundwater provides an easily accessible source of water, and generally is of suitable quality for drinking without treatment. Where public water supplies are unavailable, groundwater and private water supply wells serve a vital role in the economic development of rural areas.

Most water supply wells in the Deep and Dan River Triassic Basins are completed by first drilling and cementing surface casing to isolate the loose material at shallow depths and then drilling an open hole past the casing until reaching a sufficient quantity of water from the bedrock fractures. Some water supply wells in this area are completed as screened wells, meaning the well has been cased along its entire length, but has slots in areas where water is encountered to allow the water to enter into the well casing. Screened wells are sometimes used if the bedrock is loose and friable in order to keep the well from collapsing.

According to the available well construction records in a DENR database, the average depth for a water supply well in the Deep River basin is 261 feet, with a range of 60 to 720 feet. [157] The average depth of casing in water supply wells in the Deep River Basin is 48 feet, with range of five to 21 feet. The inventory of existing data on public water supply wells, in Section 3, includes one well 1,000 feet deep in the Deep River basin in Chatham County. In the Dan River Basin the average depth for water supply wells in the same database is 574 feet, with a range of 400 to 1005 feet. The average depth of casing in water supply wells in the Dan River Basin is 69 feet, with a range of 41 to 126 feet. The inventory of existing data on public water supply wells, in Section 3, includes one well 1,230 feet deep in the Dan River basin in Stokes County. (Well

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[154] As a matter of law, North Carolina groundwater regulations in 15A NCAC 2L .0200 classify all groundwater in the state as a potential source of potable water.
[155] Brian Grove, Chesapeake Energy. Personal communication, January 1, 2012.
[156] USGS. *Estimated Use of Water in the United States: County-Level Data for 2005.* 2010. Accessed August 1, 2011. http://water.usgs.gov/watuse/data/2005/index.html
[157] NC DENR. "GW-1" Well Construction Records Database, accessed January 31, 2012.

casing depths of less than 20 feet may occur in wells completed before 1972, the date when North Carolina well construction standards were adopted and implemented. In 1972, well construction standards began requiring well casing depths of at least 20 feet.)

The USGS, under contract to DENR, is compiling an inventory of water supply wells in the 59,000 acre potential target area identified by the NCGS in northwestern Lee County and southeastern Chatham County. This inventory will provide more detailed information about groundwater quality and water supply well construction characteristics in the potential target area. The inventory may also be useful for identifying wells that should be tested, inspected or possibly even closed prior to any additional drilling of natural gas wells. The USGS is using paper and electronic records from the N.C. Division of Water Quality and Lee and Chatham County health departments to document the locations and construction characteristics of wells in the potential target area. As of February 2012, the USGS had compiled 387 well construction records in the study area. Among these wells, well depths average 278 feet and yields average 13 gallons per minute.[158]

USGS is also compiling available groundwater quality analytical results from the local health departments and the N.C. Department of Health and Human Services. The USGS plans to collect groundwater quality samples from a subset of wells identified by this well inventory. The USGS expects to sample nine private wells and one community well near the two gas test wells drilled in 1997 and analyze these samples for dissolved gases, carbon isotopes in methane and ethane, major ions, metals, nutrients, volatile organic compounds, radium isotopes, gross alpha and beta, and strontium isotopes. The USGS expects to sample an additional 40 water supply wells in the inventory area for dissolved gases and major ions.[159] The USGS hopes to complete the well inventory by mid-April 2012 and publish results of the inventory by May 1, 2012.

In the absence of a complete inventory of water supply well locations, it may be assumed that any parcel of land in North Carolina that is not served by a community water system is served by an onsite water supply well. In some cases, a property that is served by a community water system may still have an onsite water supply well for irrigation, livestock or other uses.

Water use estimates compiled by the USGS at the county level provide an overall impression of the level to which the population in and surrounding the Triassic Basins depend on groundwater.[160] The USGS water-use estimates are not compiled at a scale finer than the county level, therefore it is not possible to characterize groundwater use within the Triassic Basins themselves. A summary of groundwater use for domestic purposes in 12 counties that contain a portion of the Triassic Basins is presented in Table 4-2. Yadkin, Davie and Union counties are not included in this table because no organic-rich shale has been reported from the basins within these counties.

Groundwater from public and private sources serves the domestic water needs of nearly half a million residents of the counties containing significant parts of the Triassic Basins, or roughly 30

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[158] Melinda Chapman, USGS. Personal communication, February 24, 2012.
[159] Melinda Chapman, USGS. Personal communication, February 24, 2012.
[160] USGS, 2010.

percent of the population in counties encompassing the Triassic Basins. In Moore County, groundwater serves the domestic water needs of three-quarters of the population of the county.

Table 4-2. Summary of Domestic Water Use in Counties containing the Deep River and Dan River Triassic Basins in 2005[161]

County	Total Population	Population Relying on Groundwater from Public Water Systems	Population Relying on Self-Supplied Groundwater	Total Population Relying on Groundwater	Percentage of Population Relying on Self-Supplied Groundwater	Total Percentage of Population Relying on Groundwater
Anson	25,499	-	2,704	2,704	11%	11%
Chatham	58,002	1,760	32,080	33,840	55%	58%
Durham	242,582	3,670	50,459	54,129	21%	22%
Granville	53,674	1,280	29,202	30,482	54%	57%
Lee	55,704	2,340	8,170	10,510	15%	19%
Montgomery	27,322	80	8,213	8,293	30%	30%
Moore	81,685	26,930	34,920	61,850	43%	76%
Orange	118,386	4,840	20,312	25,152	17%	21%
Richmond	46,781	-	7,609	7,609	16%	16%
Rockingham	92,614	2,990	40,840	43,830	44%	47%
Stokes	45,858	2,040	23,569	25,609	51%	56%
Wake	748,815	61,780	110,283	172,063	15%	23%
All 12 Counties	1,596,922	107,710	368,361	476,071	23%	30%

[161] USGS, 2010.

C. Potential groundwater impacts

Methane in groundwater

Two forms of methane can be found in groundwater: biogenic and thermogenic. Biogenic methane is formed at relatively shallow depths and is created by the decomposition of organic matter by biological activity or by the chemical reduction of carbon dioxide. Thermogenic methane is typically formed at much greater depths than biogenic methane by the thermal decomposition of buried organic material. Thermogenic methane is the type sought for natural gas development. Both types of methane can occur naturally in the subsurface environment, and the only way to distinguish between them is through isotopic analysis of the carbon atoms in the methane.

While thermogenic gas and biogenic gas are distinguished based on isotopic analysis, finding the source of natural gas migration requires investigation and analysis of several types of data – notably gas geochemistry and information on the mechanism of migration. Given the potential occurrence of multiple man-made and naturally occurring gas sources, the best way to determine whether oil and gas development has caused stray gas migration is by characterizing background groundwater quality prior to drilling activity. Stray gas migration incidents should be thoroughly investigated and supported by multiple lines of evidence, principally, geochemistry and analyses documenting a mechanism of migration.

Well construction

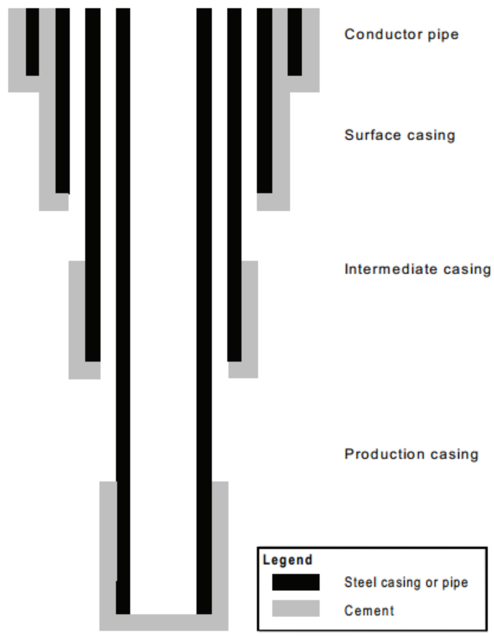
Well construction can impact groundwater quality through a number of pathways:

- The process of drilling oil or gas wells can disrupt the quality and quantity of water in water supply wells due to the circulation of drilling fluids under pressure, especially when large voids or fracture zones are encountered in the initial stages of drilling the oil or gas well.
- Improperly constructed oil or gas wells can provide a conduit for the upward migration of deeper formation water and well stimulation fluids.
- Improperly constructed water supply wells can allow contaminants in shallower groundwater to move between water bearing zones

Gas well construction

Modern hydraulically-fractured gas wells are constructed with multiple layers of casing and cement, as shown in Figure 4-1. The purpose of the layers of casing and cement is to protect both groundwater and the gas-producing zone. Typically, after the gas well has been drilled to a depth of 50 to 80 feet, a large-diameter steel pipe known as conductor casing is placed in the hole in order to keep unconsolidated materials from collapsing into the hole. This casing is cemented in place by pushing cement through the bottom of the casing and up the sides of the casing to the surface. After curing of the cement, a smaller diameter drill bit is used to continue drilling to a point below the deepest fresh groundwater. A second string of steel pipe, known as surface casing, is assembled and inserted into the borehole to this depth and cemented in place. Again, a smaller diameter drill bit is used to continue drilling to the depth of any additional zones that need to be isolated from the producing zone. An intermediate casing is then placed to this depth and cemented in place. Following curing of the cement around the intermediate casing, yet another smaller diameter drill bit is used to drill the well to the target producing zone. Upon reaching the target extent of the well, production casing is put in place and cemented. Intermediate casing is not used in every situation due to variations in geologic conditions or state regulations. Additionally, the extent of cementing around each casing string varies based on geologic conditions or regulatory requirements.

Figure 4-1. Typical Oil or Gas Well Schematic, excluding the horizontal portion of the well (from API Guidance Document HF1)[162]



After the well is constructed, explosive charges are used to perforate the production interval of the well so that fluids can move between the production casing and the target producing formation. The well is then fractured in stages, as described previously in Section 2.

A number of steps are important to ensuring protection of groundwater during construction and throughout the lifetime of a gas well. These include:

- Testing of nearby water wells and surface waters prior to drilling to establish baseline water quality conditions;
- Proper formulation and monitoring of drilling mud mixtures to maintain pressure control of the well and stabilize the hole during drilling;

[162] API. Hydraulic Fracturing Operations - Well Construction and Integrity Guidelines: API Guidance Document HF-1, 1st Edition. 2009. p. 5.

- Logging of the borehole during and after drilling to identify zones of freshwater and saltwater, oil- or gas-producing zones, and zones where cement may be lost to the formation;
- Use of appropriate casing, couplings, and centralizers to ensure that the casing can withstand the various pressures to which it will be subjected during the process of drilling, cementing, hydraulic fracturing, and production;
- Proper cement placement techniques to ensure complete filling of the spaces around the casings;
- Use of a cement with adequate strength to withstand the various pressures to which it will be subjected during its lifetime;
- Allowing an adequate waiting time between cementing casing and additional drilling, to ensure that the cement achieves its full strength before proceeding;
- Logging of the cemented casings to ensure that the cement has completely filled the space around the casing and has formed an adequate bond to the casing and borehole wall;
- Using geological data collected during drilling to design the hydraulic fracturing treatment;
- Monitoring the effects of the hydraulic fracturing itself, both at the wellhead and at the land surface overlying the horizontal portion of the well;
- Monitoring pressures in the well and between the well casings during hydraulic fracturing and production phases; and
- Proper plugging and abandonment of the well once production ceases.

At present, North Carolina regulates construction and abandonment of oil and gas wells under two complementary sets of regulations: 15A NCAC 5D and 15A NCAC 2C .0100. Neither set of regulations includes detailed technical requirements related to the steps outlined above. North Carolina's oil and gas well construction standards in 15A NCAC 5D have not been modified substantially in decades. The well construction standards in 15A NCAC 2C .0100 were revised in 2009, but their applicability to oil and gas wells was not a consideration in the rule revision process. Both sets of rules should be revised, relying on the best guidance currently available, to develop well construction standards for oil and gas activities, including horizontal drilling and hydraulic fracturing. There are no federal regulations pertaining to the construction of wells used for oil or gas exploration or production.

Water supply well construction

Proper construction of water supply wells helps protect the groundwater resource and the well user from contaminants that may be present in shallow groundwater, whether the contaminants are a result of pre-existing conditions or associated with gas exploration or production activities.

Construction of a water supply well is generally a simpler process than construction of a gas well. Generally only one or two stages of drilling are necessary, and only a single string of casing is used. The casing may be either steel or polyvinyl chloride (PVC) pipe. The casing is grouted in place using either cement or bentonite clay. The casing and cement together are intended to prevent contaminants at the land surface or in shallower groundwater from entering the water-bearing zone of the well.

As with gas wells, several steps in the construction of water supply wells are critical to protection of groundwater and the well user during construction and throughout the lifetime of the water supply well:

- Proper siting of the well relative to potential contaminant sources;
- Use of appropriate casing, couplings, and centralizers to ensure that the casing can withstand the various stresses to which it will be subjected during the process of drilling and cementing;
- Use of proper grout materials to stabilize the casing and prevent migration of contaminants around the casing;
- Proper grout placement techniques to ensure complete filling of the spaces around the casing; and
- Proper plugging and abandonment of the well once it is no longer needed.

North Carolina’s well construction standards for water supply wells in 15A NCAC 2C .0100 specify technical requirements for each of these steps. In addition, the North Carolina Well Construction Act (N.C. General Statute 87, Article 7) requires every newly-constructed private drinking water well to be permitted, inspected and tested by the local health department. Through this requirement, the local health department reviews the proposed siting of the well, observes the grouting of the well and collects a water sample from the well once construction is complete. Water samples are tested for arsenic, barium, cadmium, chromium, copper, fluoride, lead, iron, magnesium, manganese, mercury, nitrate, nitrite, selenium, silver, sodium, zinc, pH and bacterial indicators. This testing may be useful in establishing baseline water quality, but it does not include many of the chemicals that may be used or generated by oil and gas production activities, nor does it address all contamination sources that may be present in the vicinity of the well.

Potential releases to groundwater

Recent studies of the groundwater impacts of hydraulic fracturing have not produced clear evidence that hydraulic fracturing itself causes groundwater contamination. The implications of these studies have been widely debated, but a number of studies have found groundwater contamination associated with oil and gas exploration and production activities generally – if not directly attributable to hydraulic fracturing. In fact, an advisory publication from the Penn State Extension Service flatly states, “Pollution of private water supplies from gas well activity has occurred in Pennsylvania."[163] These recent studies indicate that groundwater contamination from oil and gas production cannot be attributed to a single activity, but instead may be caused by a number of activities that occur in the life cycle of a gas well. Determining the specific cause of any such groundwater contamination incident requires detailed investigation of multiple lines of evidence.

An EPA investigation of groundwater contamination near Pavillion, Wyo. found methane of thermogenic origin and organic chemicals consistent with those used in hydraulic fracturing fluids in both monitoring wells and water supply wells.[164] The relevance of this study to hydraulic fracturing generally and its applicability to hydraulic fracturing in North Carolina, however, is unclear. The hydraulic fracturing that occurred in Pavillion involved injection of hydraulic fracturing fluids directly into the same formation tapped by water supply wells, while most wells in the Triassic Basins of North Carolina are completed hundreds of feet above the target shale formations. It is unclear whether this separation distance between the water supply wells and the target shale formations in North Carolina would be sufficient to protect groundwater from contamination that could result from hydraulic fracturing.

We also do not know whether there is significant deep groundwater in the Triassic Basins and whether its quality is sufficient to serve as a source of drinking water without treatment. If such a supply of drinking water did exist, the EPA investigation into Pavillion could have more relevance in North Carolina. In any case, North Carolina's groundwater regulations treat all groundwater in its natural state as a potential source of drinking water.

Osborn and others showed that water supply wells close to active exploration and production wells in the Marcellus shale have higher levels of dissolved methane than wells farther away.[165] Their study did not find constituents of hydraulic fracturing fluids in any of the water supply wells that were sampled. The study did find methane in water supply wells. The methane had an isotopic signature indicating that it originated from deep, thermogenic sources consistent with a Marcellus shale source, rather than from shallow biogenic sources (such as manure piles or decaying organic matter). However, no background groundwater samples were available to allow comparison to methane levels prior to the commencement of hydraulic fracturing operations and the study relied solely on stable isotope data for its conclusions.

In a report to the U.S. EPA, Echelon Applied Geoscience Consulting points out, "it is essential that a thorough characterization and definition of background groundwater quality is implemented to define pre-existing conditions prior to drilling activity. Stray gas migration incidents should be thoroughly investigated and supported by multiple lines of evidence,

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[163] Penn State College of Agricultural Sciences Cooperative Extension. *Water Facts #28: Gas Well Drilling and Your Private Water Supply.* Accessed February 6, 2012. http://extension.psu.edu/water/marcellus-shale/drinking-water/gas-well-drilling-and-your-private-water-supply-2/gas-well-drilling-and-your-private-water-supply/view

[164] EPA, 2011. *Investigation of Ground Water Contamination near Pavillion, Wyoming.* http://www.epa.gov/region8/superfund/wy/pavillion/EPA_ReportOnPavillion_Dec-8-2011.pdf (accessed January 16, 2012).

[165] Osborn, S.G., et al., 2011. "Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing." *Proceedings of the National Academy of Sciences.* Accessed February 12, 2012. http://www.pnas.org/content/108/20/8172

principally, geochemistry and analyses documenting a mechanism of migration." [166] This conclusion highlights the importance of obtaining good background groundwater quality data as well as a thorough understanding of the hydrogeology of the area before any gas well drilling or hydraulic fracturing operations begin.

Researchers at Pennsylvania State University studied water supply wells before and after drilling and hydraulic fracturing operations. Their study found that bromide levels in at least one water well increased after drilling or hydraulic fracturing and that "the increase in bromide was accompanied by increases in chloride, hardness and other indicators after drilling and fracking had occurred." The study also found that "a small number of water wells also appeared to be affected by disturbances due to drilling as evidenced by sediment and/or metals increases that were noticeable to the water supply owner and confirmed by water testing results."[167]

A study by the Groundwater Protection Council (GWPC) examined groundwater contamination investigations undertaken by the oil and gas regulatory agencies in Ohio and Texas. [168] The review covered groundwater investigations in Ohio over a 25-year period (1983-2007) and Texas groundwater investigations over a 16-year period (1993-2008). Both states have active oil and gas exploration and production industries, though Texas has greater levels of activity, and a much longer history of high-volume hydraulic fracturing. According to the GWPC study, large-scale hydraulic fracturing of the Barnett Shale in Texas began in 1986, with the first hydraulic fracturing of a horizontal well occurring there in 1992. Since 1986, more than 13,000 wells have been stimulated in the Barnett Shale alone. By contrast, only one horizontal well was hydraulically fractured in Ohio during the studied period; that well was fractured in 2007.

The GWPC study examined the ultimate causes of each groundwater contamination incident (as determined by the investigating state agency) and categorized the causes based on seven phases of exploration and production:

1. Orphaned wells and sites,
2. Site preparation, including construction of access roads, grading of well pads and excavation of pits,
3. Drilling and completion, including well drilling, casing and cementing, and handling of drill cuttings, mud and fluids encountered while drilling,
4. Well stimulation, including hydraulic fracturing of both vertical and horizontal wells,

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[166] Baldassare, F.J. 2011. "The origin of some natural gases in Permian through Devonian age systems in the Appalachian Basin & the relationship to incidents of stray gas migration," U.S. EPA, *Proceedings for USEPA Technical Workshop for Hydraulic Fracturing Study, Chemical & Analytical Methods.* Accessed February 10, 2012. http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/upload/proceedingsofhfchemanalmethodsfinalmay2011.pdf,

[167] Boyer, Elizabeth W. et al. "The Impact of Marcellus Gas Drilling on Rural Drinking Water Supplies." *Publications*. The Center for Rural Pennsylvania. Accessed January 24, 2012. <http://www.rural.palegislature.us/documents/reports/Marcellus_and_drinking_water_2011_rev.pdf>

[168] Groundwater Protection Council, 2011. *State Oil and Gas Agency Groundwater Investigations And Their Role in Advancing Regulatory Reforms.* Accessed January 16, 2012. http://www.gwpc.org.

5. Production, on-lease transport and storage, including on-site handling of oil, gas and produced water, repair and maintenance of the production well, and use of pits for waste handling and disposal during the production phase,
6. Waste management and disposal, including landfarming, landspreading, road application or disposal by injection wells, and
7. Plugging and site reclamation after production has ceased.

A summary of the contamination incidents grouped according to the phase of oil or gas production in which the authors determined contamination occurred is presented in Table 4-3.

Table 4-3. Summary of the Sources of Groundwater Contamination from Oil and Gas Production in Ohio and Texas

Phase	Number of Incidents	
	Ohio (1983-2007)	Texas (1993-2008)
Orphaned wells and sites	41	30
Site preparation	0	0
Drilling and completion	74	10
Well stimulation	0	0
Production, on-lease transport, and storage	39	56
Waste management and disposal	26	75
Plugging and site reclamation	5	1
Unknown	(none reported)	39

Potential public health impacts

The different contaminants associated with oil and gas operations present varying degrees of potential public health risks. Without knowing the composition of chemicals that might be used in the process of developing natural gas in North Carolina, it is not possible to say what specific health risks the release of drilling chemicals into groundwater would pose.

North Carolina's groundwater quality standards are established based on the intended use of groundwater as a source of drinking water. These standards establish the maximum allowable concentration of contaminants that may be tolerated without creating a threat to human health or rendering the water unsuitable for its intended use. The current groundwater standards specify concentration limits for more than 140 constituents. For any constituent without an existing numeric standard, the standard is established by default at the practical quantitation limit. New standards may be established higher than the practical quantitation limit (the lowest level at which a laboratory may accurately measure the concentration of the contaminant) if an interested party provides sufficient toxicological and epidemiological data and other calculations to support a new standard.

Consumption of drinking water containing dissolved methane does not pose a public health risk. However, in high concentrations methane can pose a threat of asphyxiation because it displaces oxygen in the air. In addition, methane and oxygen in an enclosed environment, such as a house or other dwelling, can pose an explosion or fire hazard.

Conclusions related to groundwater

We recommend that the General Assembly require each oil and gas operator to obtain background groundwater quality data from existing water supply wells near the proposed drill site before drilling begins and to share this data with the regulatory agency. Each water supply well located within a distance determined by the horizontal extent of the hydraulically fractured well should be sampled and analyzed for dissolved methane, volatile and semi-volatile organic compounds, chloride, total dissolved solids, bromide, and dissolved metals.

D. Process wastewater

Wastewater characteristics

Volume generated and patterns of generation in time

The process of hydraulic fracturing generates two types of wastewater: "produced water" and "flowback." Produced water is the groundwater naturally found in shale formations. Contact with the shale causes groundwater in these formations to take on high levels of total dissolved solids as well as minerals including barium, calcium, iron and magnesium. Flowback consists of a combination of produced water with the fluids that are injected into the well by the drilling operator. During the days or weeks immediately following hydraulic fracturing, flowback makes up most of the wastewater that returns to the surface and consists primarily of the hydraulic fracturing fluids. The volume of flowback reported in the Marcellus shale in northern Pennsylvania ranges from 9 – 35 percent of the fluid pumped into a well for hydraulic fracturing.[169] During the remainder of the productive life of the well, a much smaller volume of wastewater is generated more or less continuously as the well produces gas; this wastewater is produced water.

Chemical characteristics of the wastewaters

Due to variations in geological conditions, the constituents in the flowback water from potential shale gas production sites in North Carolina may differ substantially from those found in currently active sites in Pennsylvania, Ohio or Texas. The specific formulation of hydraulic fracturing fluids used will also affect the characteristics of the flowback waters. Data from existing well fields can be used, however, to generally illustrate the broad categories of chemical characteristics that must be considered in managing wastewaters generated by gas production.

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[169] NYSDEC, p. 5-99.

Table 4-4. Typical Range of Concentrations for Some Common Constituents of Flowback Water in Western Pennsylvania[170]

Constituent	Low (mg/l)	Medium (mg/l)	High (mg/l)	Average Concentrations in Seawater[171]
Total Dissolved Solids	66,000	150,000	261,000	34,580[172]
Total Suspended Solids	27	380	3,200	Not Reported
Hardness (as CaCO3)	9,100	29,000	55,000	Not Reported
Alkalinity (as CaCO3)	200	200	1100	Not Reported
Chloride	32,000	76,000	148,000	19,000
Sulfate	ND	7	500	2,700
Sodium	18,000	33,000	44,000	10,500
Calcium, total	3,000	9,800	31,000	410
Strontium, total	1,400	2,100	6,800	8
Bromide	720	1,200	1,600	67
Iron, total	25	48	55	0.0003
Manganese, total	3	7	7	0.0020
Oil and grease	10	18	260	Not Reported
Total radioactivity	ND	ND	ND	Not Reported

ND = Not Detected

Although not detected in the data from western Pennsylvania, naturally occurring radioactivity may also be present in produced water in any shale gas field. It is not yet known what levels of naturally occurring radioactivity may be present in produced waters, and thus in flowback water, from North Carolina shale deposits.

Bromide is a pollutant of concern, not because of its own toxicity, but because of its potential to cause toxic disinfection byproducts during chlorination of drinking water. Bromide is not removed by normal wastewater treatment, nor is it removed by conventional drinking water treatment plants. If wastewater containing bromide is discharged to surface waters supplying a downstream drinking water treatment plant, it can lead to the creation of toxic byproducts during the disinfection process. It is difficult to measure bromide concentrations in brine solutions such as produced waters due to extremely high chloride concentrations. EPA is attempting to develop a quantitative relationship between the levels of bromides discharged into water bodies and toxic disinfection byproducts in drinking water.

The constituents listed in Table 4-4 do not include the compounds that are added to the hydraulic fracturing fluid, any of which could be present in the flowback water. The industry has

[170] Gregory, K.B., et al. 2011. "Water Management Challenges Associated with the Production of Shale Gas by Hydraulic Fracturing." *Elements* v. 7 no. 3, pp. 181-186.
[171] Hem, John. *Study and Interpretation of the Chemical Characteristics of Natural Water.* USGS Water Supply Paper 2254, 1989.
[172] Calculated by DENR from total of constituents reported in Hem, 1989.

identified at least 44 chemicals used in shale gas production including the following: glutaraldehyde, quaternary ammonium chloride, tetrakis hydroxymethyl-phosphonium sulfate, ammonium persulfate, isopropanol, methanol, ethylene glycol, naphthalene and 2-butoxyethanol. Any of the chemicals used in hydraulic fracturing could be present in flowback water.

It is difficult to predict the exact composition of wastewater that would be generated by a hydraulic fracturing operation in North Carolina. The constituents in the wastewater are affected by both the characteristics of the shale play and the mixture of compounds used in the hydraulic fracturing fluids. For example, the produced waters from Barnett Shale in Texas are typically lower in total dissolved solids (TDS) concentration than those from the Marcellus Shale in Pennsylvania.[173] Oil, grease and volatile organic compounds are highly variable even within a particular formation. As a result, the flowback water from a North Carolina gas well may have a different makeup than the data cited above would suggest. It may not be possible to fully characterize flowback waters from shale gas operations in North Carolina until there is actual wastewater from a North Carolina hydraulic fracturing operation.

On-site storage of drilling fluids, hydraulic fracturing fluids, produced water and flowback

Often, on-site storage structures are used to provide temporary storage for drilling muds, hydraulic fracturing fluids, flowback, produced water, emergency overflow, oil and other fluids until they can be conveyed to a facility for disposal or reuse. On-site storage can be in pits excavated in the ground, or in above-ground containment systems such as steel tanks.

The failure of a tank, pit liner or the pipeline carrying fluid ("flowline") may result in contamination of surface water and shallow ground water. An accidental spill or release can have negative impacts on human health, wildlife, plants and ecosystems. Environmental cleanup – especially where surface water or groundwater has been contaminated – is costly and time consuming. Therefore, prevention of releases is vitally important.

For excavated pits, infiltration of fluids into the ground is a serious concern. Typically, pit liners are constructed of compacted clay or synthetic materials like polyethylene or treated fabric that can be joined using special equipment. The GWPC study of contamination incidents associated with oil and gas operations found that unlined or inadequately constructed pits for drilling mud or produced water were one of the most common sources of groundwater contamination in Ohio.[174]

Under current North Carolina regulations, wastewater storage ponds are required to meet design standards to be protective of groundwater. Demonstration of liner specifications is required to ensure that maximum hydraulic conductivity or groundwater standards are not exceeded. Use of clay or synthetic liners or the use of predictive modeling of the groundwater may be used to demonstrate adequate protection.

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[173] Kelvin Gregory, Assistant Professor of Environmental Engineering, Carnegie Mellon University, personal communication, January 17, 2012.

[174] GWPC, 2011.

New systems have been developed that avoid the use of pits. One technology that is becoming more common is "closed-loop" fluid handling systems. These systems avoid the use of pits by keeping fluids within a series of pipes and tanks throughout the entire fluid storage process. Since fluid is never placed into contact with the ground, the likelihood of groundwater contamination is minimized.[175]

Disposal options for wastewaters

Four major options exist for disposal of wastewaters produced by oil and gas operations, including hydraulic fracturing operations: Class II injection wells: disposal by a publicly-owned treatment works (POTW) under a pretreatment program; reuse or recycling as fracturing fluids; and land application. A number of factors may make some of these options impractical or undesirable for use in the Triassic Basins of North Carolina.

Class II Injection Wells

One option used in other states for disposal of produced water and flowback water from hydraulic fracturing is by underground injection of the wastewater. EPA has delegated the authority to issue permits for injection wells under the federal Safe Drinking Water Act's Underground Injection Control (UIC) provisions to DENR's Division of Water Quality. The UIC program sets standards for several different classes of injection wells. Under the federal rules, a Class II injection well can be used to inject wastewater generated in the production of oil and natural gas. According to the EPA, approximately 80 percent of Class II injection wells in the United States are used for enhanced oil and gas recovery; the remainder are used for disposal of wastewater fluids from the shale gas exploration and production process into the original oil- or gas-bearing formation or a similar formation.[176] Federal regulations require Class II injection wells to be constructed and operated in a manner that is protective of underground sources of drinking water.

N.C. General Statute 143-214.2(b) prohibits the use of wells for waste disposal. To preserve options for future water supply, state rules also classify all groundwater in North Carolina as a potential source of drinking water. As a result, state law does not currently allow permitting of Class II injection wells. The nearest Class II injection wells are in western Virginia, but the UIC permits issued by EPA only allow those wells to accept wastewaters that are generated from the oil or gas production with which they are associated.

Even if North Carolina law were changed to allow underground injection of waste, it is not clear that injection wells would be a feasible option for managing produced waters from a gas well in the Triassic Basins. The areas with potential for natural gas development have not been sufficiently characterized to determine whether the formations would be suitable for disposal of shale gas production wastewater. The sedimentary rocks of these basins generally have very low permeability, and natural fractures are responsible for nearly all of the permeability and

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[175] FracFocus.org, "Fracturing Fluid Management." Accessed January 31, 2012. http://fracfocus.org/hydraulic-fracturing-how-it-works/drilling-risks-safeguards.

[176] EPA. "Class II Wells – Oil and Gas Related Injection Wells (Class II)." 2011. Accessed January 20, 2012. http://water.epa.gov/type/groundwater/uic/class2/index.cfm

groundwater movement in these basins. As mentioned previously, sedimentary rocks in the Sanford sub-basin tend to have very low permeability due to the presence of fine-grained material commonly occurring within the spaces between the larger grains. Instead, most of the ability of these formations to produce or receive water is due to fractures in the rock. Disposal by injection into fractured rock presents difficulty in predicting the fate and transport of the injected wastewaters. These conditions suggest that Triassic Basins in North Carolina generally do not have suitable hydrogeologic conditions for disposal by injection.

States with both active oil and gas production and active Class II injection wells do not allow injection into the production zone in order to prevent degradation of the oil or gas-producing zones.[177] The exception is to allow disposal in the oil or gas producing formation in such a way that enhances the recovery of oil or gas. Otherwise, produced wastewaters are typically disposed of in other formations or zones that do not produce oil or gas.

The Coastal Plain of North Carolina is underlain by formations that could have properties more suitable for disposal of process wastewaters. However, multiple aquifers in the Coastal Plain are actively used as sources of drinking water, and others have the potential to be used as sources of drinking water and are protected as such under 15A NCAC 2L. 0200.

Federal UIC rules do not allow injection of wastewater into Underground Sources of Drinking Water (USDW). Although North Carolina classifies all groundwater as a potential drinking water source, the EPA definition of USDW excludes aquifers containing groundwater with total dissolved solids (TDS) levels of 10,000 mg/L or greater.[178] A limited number of areas in the Coastal Plain of North Carolina are known to have groundwater having TDS of 10,000 mg/L or greater. However, those areas are at least 120 miles away from the Deep River Triassic Basin. The relatively shallow depth of some of these aquifers may not provide sufficient separation from potential drinking water supplies to allow for the safe disposal of produced waters. Thus even adopting the EPA's definition for drinking water aquifers may not open up options for disposal of wastewaters by deep well injection.

If an appropriate underground disposal site could be identified, successfully siting and constructing a disposal well and associated infrastructure would require a thorough hydrogeologic evaluation of subsurface conditions thousands of feet below ground as well as assessments of environmental impacts to surface features. This assessment process would be both costly and time-consuming. Even the coastal plain aquifers that fall outside the EPA definition of USDW may not have hydrogeologic conditions suitable for injection, due to their generally low permeability.

Administratively, creation of the necessary regulatory framework to allow injection of wastewater from drilling operations would require development of a state regulatory program for Class II wells. Since North Carolina law prohibits underground injection of wastes, the state has no standards for siting, construction and operation of waste injection wells. The program

[177] Based on conversations with Class II injection well programs in Montana, Colorado, Alabama, and Louisiana. January 2012.

[178] Code of Federal Regulations, Title 40, Part 144.3

change would require the state to re-apply to the EPA for approval of the revised UIC program; that process can be lengthy.

Disposal by publicly-owned treatment works or centralized waste treatment facility

Disposal to a Publicly-Owned Treatment Works (POTW), also known as a municipal wastewater treatment plant, is another option for disposal of wastewaters from oil and gas exploration and production. Wastewater is transported to the POTW by pipeline or by tanker truck. Due to the high strength and unique characteristics of certain industrial wastewaters, including wastewaters generated by oil and gas production, pretreatment of wastewater is necessary in order to protect the receiving POTW and its receiving stream. Federal rules require pretreatment in order to prevent pass-through of pollutants to the receiving stream in amounts greater than the National Pollutant Discharge Elimination System (NPDES) permit limit or stream standard, prevent interference with the wastewater treatment processes, and promote the beneficial reuse of biosolids. [179]

Wastewater from oil and gas production operations may first be transported to a centralized waste treatment facility (CWT) for pretreatment before final disposal to the POTW. CWTs accept wastes from many types of industry for treatment, and then discharge treated wastewater to local wastewater treatment plant under a pretreatment permit or to surface waters under an NPDES permit.

Federal regulation of CWT facilities covers three subcategories of pretreatment: metals treatment and recovery, oils treatment and recovery and organics treatment and recovery. Wastewater containing oil and grease in excess of 100 mg/l should be classified in the oils subcategory. Wastewater that contains less than 100 mg/l of oil and grease but has any of the following pollutants in excess of the concentrations listed should be classified in the metals subcategory: cadmium (0.2 mg/l), chromium (8.9 mg/l), copper (4.9 mg/l) or nickel (37.5 mg/l). Wastewater that does not fit into one of the first two subcategories is considered “organics.”

EPA has established standards for each pretreatment category in 40 CFR Part 437. Since EPA did not consider the hydraulic fracturing industry when developing the categorical standards, the standards may not address all of the pollutants of concern generated from shale gas production. Based on local site-specific factors, a POTW with a pretreatment program may establish limitations for pollutants not covered by the federal regulation and may require more stringent limits for covered pollutants. A pretreatment facility may be able to provide targeted treatment for specific pollutants of concern associated with natural gas extraction and make the treated wastewater much more acceptable to the POTW.

In North Carolina, any POTW that accepts wastewater from a significant industrial user (SIU) must have a state-approved pretreatment program. An SIU is an industrial user that:

1. discharges an average of 25, 000 gallons per day or more of process wastewater;
2. contributes 5 percent or more of the treatment plant capacity for flow or biochemical oxygen demand (BOD), total suspended solids (TSS) or ammonia;

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[179] 40 CFR 403.2

3. is subject to categorical regulations described above; or
4. is designated as an SIU by the POTW because the industry's wastewater could adversely affect the operation of the POTW.

North Carolina has eight CWTs permitted through local pretreatment programs. One is permitted for direct discharge through the NPDES program, but the facility plans to shut down the CWT operation in the near future.

One of the tools used to accomplish the goals of the pretreatment program is the Headworks Analysis (HWA). The HWA calculates the amount of pollutants that can safely enter the POTW while meeting the goals of the program. Three criteria are examined in the conventional pollutant HWA:

- Pass-through calculations evaluate compliance with NPDES permit limits or water quality standards and serve to protect the stream into which the POTW discharges.
- Inhibition calculations evaluate allowable loadings that will not inhibit or interfere with the treatment process and serve to protect the treatment plant.
- Sludge calculations ensure that the biosolids produced are acceptable for land application. Organic parameters are evaluated using a separate spreadsheet and this evaluation addresses worker health and safety by including an evaluation of explosivity, permissible exposure limit (PEL) and short-term exposure limit (STEL) concentrations.

Each POTW that provides pretreatment performs the headworks analysis based on the characteristics of the individual wastewater treatment plant. Results will vary from POTW to POTW. It is the responsibility of the individual POTW to use scientific data and best professional judgment to determine if a particular waste stream will be compatible with the treatment plant and to decide whether to accept the waste stream.

Typical parameters for the HWA are: biological oxygen demand (BOD), TSS, ammonia, arsenic, cadmium, chromium, copper, cyanide, lead, mercury, molybdenum, nickel, selenium, silver, zinc, total nitrogen and total phosphorus. Site-specific data is used to calculate removal rates. Literature removal rates are available if there is insufficient data or a removal rate cannot be calculated because a majority of the data is below the quantitation limit of the analytical method.

Many of the compounds that may be present in shale gas production wastewater are not included in the typical HWA parameters. Often, the Classification and Standards Unit of the N.C. Division of Water Quality can provide an aquatic life or human health standard for these compounds. A removal rate based on scientific literature can be obtained from EPA's Risk Reduction Engineering Laboratory (RREL) Treatability Database. Other sources for data may be the HWAs of other North Carolina POTWs.

Some shale gas production wastewater also has naturally occurring radioactivity. North Carolina has dealt with the issue of treating radioactive wastewater in a wastewater treatment plant before. In the past, the issue arose because of the disposal of drinking water treatment residuals in which naturally occurring radioactive materials had been concentrated. In this context, the N.C. Radiation Protection Section (Department of Health and Human Services, Division of Public Health) clarified the requirements in 49 CFR Part 173 Subpart I regarding the general requirement for shipments and packaging of Class 7 (Radioactive) Materials.[180] The federal rule specifically states in Part 173.401 (b) (4) that this subpart does not apply to: "Natural material and ores containing naturally occurring radionuclides which are not intended to be processed for use of these radionuclides, provided the activity concentrations of the material does not exceed 10 times the values specified in 173.436." It is not yet known whether produced waters from North Carolina shale deposits will contain other hazard classes that would then be subject to the requirements in Part 173.423, Requirements for Multiple Hazard Limited Quantity Class 7 (Radioactive) Materials.

Even in the absence of specific water quality standards for all expected pollutants, the POTW can use the information the Headwaters Analysis as a starting point for conducting inhibition and toxicity studies. Laboratory studies can be conducted using actual treatment plant influent and produced water to determine the compatibility of the wastewater with the treatment plant.

Land application

Land application is another option used in many states for disposal of wastewaters produced by oil and gas operations. In many western states, oil and gas production wastewaters are used for de-icing or dust control on roads.

In North Carolina, land application of wastewater requires treatment of the wastewater to meet specified quality standards prior to disposal. North Carolina has existing standards for both land application and infiltration systems; those can be found in 15A NCAC 02T .0500 and 15A NCAC 02T .0700, respectively. The rules and individual permit conditions specify setbacks, land-application rates, and the timing of land application to protect groundwater, surface water, and public health. North Carolina rules could potentially allow for land-application or infiltration of wastewater from gas production by irrigation of vegetated land, disposal in an infiltration basin, or beneficial reuse. In each case, the applicant would need to demonstrate compliance with current technical criteria

Surface irrigation systems involve controlled surface application of wastewater effluent on a vegetated land surface by using spray heads or a drip system. These systems use the natural ecosystems to incorporate the wastewater effluent. The effluent is absorbed into the atmosphere through evaporation or volatilization, into the soil through filtration and into plants through nutrient uptake and the degradation of microorganisms.

Infiltration basins involve the controlled application of wastewater effluent to the ground and rely on infiltration as the primary mechanism of disposal. Application methods include rotary distributors, spray beds and infiltration basins. High-rate infiltration systems land apply treated effluent at rates greater than 91 inches per year (in/yr) for coastal areas and 873.6 in/yr for non-coastal areas. A standard infiltration basin is any basin that does not exceed the threshold to be considered a high-rate system. Application rates are based on soil properties and surficial

[180] Beverly Hall, Chief, Radiation Protection Section, November 27, 2006. Memorandum to DWQ on disposal of wastewater associated with water supply wells with potential radiological components.

aquifer characteristics. For high-rate systems, groundwater quality standards are designed to be met through more stringent effluent nutrient limits, and more stringent setbacks are in place. It is highly unlikely that site conditions in the Triassic Basin will provide sufficient infiltration for a basin to be considered a high-rate infiltration basin.

It is also possible that the shale gas production wastewater could be treated to meet reclaimed water standards established in 15A NCAC 02U. Reclaimed water is highly treated wastewater effluent that can be used for beneficial purposes such as for golf course irrigation, firefighting or cooling water. Wastewater that meets reclaimed water standards may be permitted for reuse with reduced reporting and setback requirements. The possibility of reuse of the wastewater produced by oil and gas production will depend on the cost of treatment to meet the reclaimed water standards and the availability of potential users for the reclaimed water.

Wastewater produced by a natural gas operation would be classified as an industrial wastewater and permitting requirements for land application of the wastewater would be consistent with those applied to any other industrial wastewater. The state's land application rules set minimum design standards for the wastewater treatment and disposal system; establish setbacks from features such as streams; and require the applicant to demonstrate adequate operation and maintenance procedures.

Disposal of wastewater generated by oil and gas production by land-application or infiltration poses some significant challenges in the Triassic Basin due to the wastewater characteristics and the soil and subsurface conditions typically found in the area. All land-application wastewater systems require a site evaluation to ensure that the site can handle the waste. Due to the high variability in the chemical characteristics of the wastewaters and its classification as an industrial wastewater, a site-specific hydrogeologic evaluation and groundwater modeling would be required for each potential disposal site. The evaluations would consider the proposed method of treatment, available land area and subsurface conditions on the site to determine if the wastewater can be applied in a manner protective of the groundwater.

High salinity can present a potential problem in using wastewater recovered from oil and gas production for crop irrigation. Water salinity refers to the total amount of salts dissolved in the water, primarily from calcium, magnesium and sodium ions dissolved in the water. A high level of salts in irrigation water reduces water availability to the receiving crop and can reduce yield. When sodium salts dominate the total salinity, the forces that naturally bind clay particles together in the soil are disrupted, causing clay particles to expand and reduce the permeability of the soil.

Considering the chemical characteristics of flowback water presented in Table 4-4, the concentration of both sodium and total chlorides presents another potential limitation on the suitability of land application of produced waters. Sodium may have adverse effects on the very shallow soils found in the Triassic belt of North Carolina. A combination of efficient drainage and flushing of the soil by water is often used to leach salts from the profile. The soils of this region have a hard subsurface with low permeability. The applied salts may accumulate on the surface layers for a long time, causing the topsoil to further degrade and affecting plant growth adversely.

Soil characteristics are also a key component to the proper design and management of non-discharge systems. Soils in the Triassic Basin typically have low hydraulic conductivity, which limits their utility as non-discharge systems. Loading rates for permitted facilities surrounding the Sanford sub-basin ranged from 20 to 80 inches per year. Using a 20 to 80 inches per year range of application rates, an anticipated average of five (5) million gallons per well, and a conversion of 27,000 gallons for an acre-inch, an expected range of 2.3 to 9.3 acres would be required to dispose of the average volume of waste from each well. (Please note that variation in volumes of wastewater generated at a well site and on-site soil characteristics will greatly impact the amount of land necessary to manage wastewater, and actual land requirements could be outside of the estimated range).

It should be noted that 15A NCAC 2T .0113(a)(10) provides an exemption from regular permitting for land application of "drilling muds, cuttings and well water from the development of wells or from other construction activities including directional boring." This exemption was intended to address wastes generated by water well construction and utility borings. However, it is written in such a way that it could allow essentially unregulated disposal of these wastes from any type of well, and could even be construed to pertain specifically to horizontal drilling of gas wells.

It is not likely that produced waters could be used for road de-icing or dust control under North Carolina's land application rules. Unlike many western states where "roadspreading" of wastewater is allowed, North Carolina has a large network of streams and wetlands; road drainage features would in many instances direct the wastewater to surface waters.

Potential for recycling/on-site pre-treatment techniques

On-site treatment of the flowback or produced water prior to disposal or transportation to a permitted wastewater treatment facility may be required as part of wastewater management. If wastewater management includes either discharge to a municipal or private wastewater treatment system not owned by the oil and gas developer, or if the water is managed as part of a land application system owned by the gas developer, it is likely that on-site treatment will be necessary. Due to the variations in flowback water quality, and requirements for disposal, a site-specific evaluation will be necessary to determine the necessary treatment system. However, due to the high dissolved solids found in flowback water at other sites, it is likely that membrane filtration, reverse osmosis, thermal distillation or other high level treatment strategies will be necessary to achieve the treatment criteria needed for disposal. These types of treatment systems are proven to effectively remove dissolved solids from a wastewater; however, these treatment systems also produce a concentrate of dissolved solids that will need to be managed.

Chesapeake Energy is currently recycling and reusing 100 percent of the flowback water that returns to the surface (only a small percentage of the volume of water used in hydraulic fracturing) by a filtering process that uses a 20-micron filter.[181] The filtration process removes suspended solids that form a filter cake composed of sand and rock material. This material is

[181] Brian Grove, Chesapeake Energy. Personal communication, February 1, 2012.

disposed of in permitted landfills.[182] Chesapeake no longer disposes of any produced water by wastewater treatment plants that discharge to rivers or streams in Pennsylvania. The water produced during flowback operations is collected and stored in onsite storage tanks. The benefits of recycling wastewater include using less freshwater for hydraulic fracturing, reducing the impact on local water supplies, reducing the amount of truck traffic for hauling water, reducing noise and air pollution due to truck traffic, and reducing the costs of operation.[183]

Instances can occur where there is more water than can be readily processed and reused, typically during large rain events. In these instances, Chesapeake has used an evaporative distillation treatment system, provided by a local contractor, along with Class II injection wells to dispose of the temporary surplus. [184]

Closed-loop recycle systems are defined in 15A NCAC 02T .1000 as wastewater systems where nondomestic wastewater is repeatedly recycled back through the process in which the wastewater was generated. Requirements for closed-loop recycle systems are established in 15A NCAC 02T.1000. Closed-loop recycle systems do not include recycling of wastewater from groundwater remediation systems though an injection well or infiltration gallery specifically covered by administrative code for groundwater remediation systems (15A NCAC 02T .1600). The recycling of wastewater recovered during flowback for use as an injectant would not be allowed due to GS 143-214.2(b), which prohibits the injection of wastes into groundwaters of the state.

While recycling wastewaters as fracturing fluids has proven to be an effective wastewater management option for Chesapeake Energy in Pennsylvania, the usefulness of this practice in the Triassic Basins of North Carolina may be limited due to geologic and hydrogeologic conditions. The shale that is being used for fracturing in Pennsylvania lies at depths of roughly 10,000 feet. The deepest water supply wells in that area are generally no more than 600 feet deep, and it is not uncommon to encounter highly saline groundwater at depths of 600 to 750 feet.[185] By contrast, 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.

Disposal options for treatment residuals

Residuals generated as part of oil and gas production must be managed to ensure protection of surface and groundwater resources. The Division of Water Quality's (DWQ) Residuals Management Program regulates the treatment, storage, transportation, use and disposal of residuals as specified in 15A NCAC 02T: Waste Not Discharged to Surface Waters. Under these rules, residuals have been defined as any solid, semi-solid or liquid waste, other than effluent or residues from agricultural products and processing, generated from a wastewater treatment

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[182] Ibid, February 1, 2012.
[183] Ibid, February 1, 2012.
[184] Ibid, February 1, 2012.
[185] Ibid, February 1, 2012.

facility, water supply treatment facility or air pollution control facility permitted under the authority of the Environmental Management Commission (EMC). Rules specific to Residuals Management are located in Section .1100 of Subchapter 02T. Depending on the quality of the residuals, the generator may land-apply the residuals for beneficial use or dispose of the residuals in a surface disposal unit. Residuals not meeting minimum requirements could be further processed until requirements are met, or sent to a permitted landfill or incinerator for disposal.

The quality of the residuals is critical to assure that proper management practices are matched with the residuals to assure that they are land applied, or disposed of, in a safe manner. The quality of the residuals is dependent on the characteristics of the wastewater being treated, and the type of wastewater treatment and sludge stabilization process used. Residuals quality requirements for land application include demonstration that the residuals are non-hazardous, metals and pathogen concentrations do not exceed a ceiling limit, micro nutrient values for nutrient management are met, and prescribed methods for pathogen and vector attraction reduction are met.

E. Surface water impacts and stormwater management

Oil and gas exploration and production activities present environmental risks similar in character to other industrial and construction activities already regulated under existing stormwater management programs administered at the state and local levels for the protection of surface waters. Some of the activities associated with oil and gas exploration and production are exempt from federal stormwater permitting requirements that apply to other industrial and construction activities in North Carolina.

Generally, environmental impacts from stormwater flows arise from three characteristics of the interaction between industrial and construction activities and rainfall runoff flows: pollutant transport, overtopping of containment structures, and increases in the rate and volume of runoff.

First, as rainfall runs across the surface of the industrial or construction areas the rainwater picks up any pollutants that may be on the surface and carries those pollutants to streams, rivers and lakes. This is especially true for stormwater runoff from asphalt, concrete, gravel and dirt roads, other impervious surfaces, outdoor industrial activity and earthen construction sites, where any material collected on the ground in the course of normal operations may be washed into a nearby surface water body. In the event of a spill due to equipment malfunction or operator error, large amounts of pollutants can be delivered to the receiving waters in a very short amount of time.

Second, unusually heavy rainfall has the potential to overwhelm the excess storage capacity of open top tanks or pits containing process chemicals or waste materials as well as berms that may be enclosing a well pad, and can cause the unintended release of the harmful materials along with the excess rainfall. The New York Department of Environmental Conservation reviewed several spill incidents in the hydraulic fracturing industry, and reports on the Chesapeake Energy spill in Pennsylvania, stating that,

> "On April 19, 2011, an uncontrolled flow of hydraulic fracturing fluid occurred during fracture stimulation of Chesapeake Energy's Atlas 2H well in LeRoy Township, Bradford County...a failure occurred at a valve flange connection to the wellhead, causing fluid to be discharged from the wellhead at high pressure. Approximately 60,000 gallons of fluid were discharged to the well pad, of which 10,000 gallons flowed over the top of the containment berms. A portion of this fluid made its way into an unnamed tributary of Towanda Creek. The wellhead failure is under investigation to determine the precise cause of the breach. The wellhead was pressure-tested after installation and after each hydraulic fracturing stage prior to the breach. According to Chesapeake officials, it passed all tests. The discharge of fluid from the well pad was caused by the failure of stormwater controls on the well pad due to extraordinary precipitation and other factors."[186]

Incidents like this can cause pollutants in high-brine flowback waters to enter freshwater streams and rivers. Other pollutants contained in hydraulic fracturing fluids could be released as well, which also could pose threats to the aquatic environment.

Third, runoff typically increases where hard surfaces and paved areas are constructed. Standard industrial site layout is designed to remove rainwater from the working area as quickly as possible so as not to impede the safe conduct of production operations. The result is more runoff volume, delivered more quickly, to the receiving water. The sudden increase in volume can cause stream bank and streambed erosion that degrades the habitat quality of the water body. For small rain events or small sites, the habitat degradation can be transient and the receiving waters may be sufficiently resilient to recover quickly. Variation in flow volume with the seasons and in response to large rain events is natural and some scouring of the streambed becomes part of the natural variability of the aquatic habitat. But for large projects or sizable sediment loads, the effects can be long-term and result in permanent stream degradation. So in addition to the chemical pollutants and eroded sediment originating from the well pad, increased in-stream erosion from artificially increased flow volumes can degrade streams.

A well pad has the potential to generate all three stormwater problems. While the pollutant generation and transport mechanisms are similar to other industrial and construction activities, oil and gas exploration and production activities are not regulated to the same extent as other industrial activities. The potential impacts of stormwater runoff from a drilling site include:

- Contamination of surface waters with hydraulic fracturing fluids
- Contamination of surface waters with sediment, nitrogen compounds and other pollutants
- In-stream erosion
- Habitat degradation

[186] NYDEC, pp. 10-2 – 10-3.

Erosion and sedimentation issues during production and following reclamation of well pads

Erosion and sedimentation from the construction of the well pad and from subsequent production activities deserve special attention. Sediment has been identified as the largest water quality problem in North Carolina. Environmental agencies use a variety of ways to measure sedimentation pollution: 1) the presence of visible sedimentation deposited in a stream bed; 2) total suspended solids (TSS) in the stormwater discharge entering a creek; and 3) in-stream turbidity. The potential for excess sediment in a creek can be mitigated through both operational and structural stormwater practices.

For sediment originating in erosion of the well pad itself, either during construction or during operations, the following preventive measures may be appropriate:

- Stabilize the disturbed earth as soon as possible after or even during phases of the grading operation with fast germinating grasses. Rigorously maintain these areas once stabilized.
- Coordinate the grass stabilization with the sequence of construction and site activities to afford maximum continuing protection.
- Employ sediment capture basins to keep eroded sediment on site.
- Continue inspections and maintenance of the sediment control measures even during periods of less intense activity, such as the production phase.

The federal Energy Policy Act of 2005 exempted oil and gas activities from federal construction stormwater permitting requirements under the Clean Water Act. Those permitting requirements specifically address sedimentation pollution and turbidity impacts associated with construction activities. State sedimentation control requirements still apply; compliance with the North Carolina Sedimentation Pollution Control Act, N.C. General Statute 113A, Article 4, will require the industry to implement many of the measures described above in the construction of well pads and other infrastructure associated with exploration and production of natural gas.

Post-development runoff

To prevent in-stream erosion and habitat degradation due to increased stormwater runoff and the resulting increased flow in the receiving water, the following preventive measures may be appropriate:

- Structural stormwater controls should provide enough freeboard to accommodate a large design rainfall.
- Structural stormwater controls should incorporate a peak flow shaving element in the outlet structure design. Standard outlet structure design typically accomplishes peak flow reduction with submerged orifices, floating outlets, or constraining weirs.
- Qualified personnel should assess the morphology of nearby streams in order to evaluate how much excess flow the stream can accommodate before in-stream erosion

is probable. This assessment should be either accomplished by regulatory staff, or subject to regulatory review and approval.

- After site operations cease, the potential for site erosion and for increased stormwater runoff remains unless close out activities include stabilization of the abandoned well pad. Re-vegetation of the site should be required as part of close out requirements.

It appears that the greatest risk of stormwater pollution and receiving water impacts is during the more intense stages of natural gas extraction, such as clearing and grading, mobilization and set up, hydraulic fracturing and re-fracturing, and demobilization and knock down. Once the site is producing natural gas, stormwater runoff can potentially carry less risk, assuming that as part of site reclamation activities, the pad has been successfully stabilized and that any remaining production activities are much smaller in scope, have containment, and operators provide routine inspection, maintenance, and repair. However, if the well pad continues in production with reduced staff or no staff, the risks associated with production are still present, but there may be fewer resources available for immediate response to a stormwater pollution emergency.

Stream and wetland impacts

Streams and wetlands are protected under both state and federal law because of the many beneficial functions they provide. Streams support aquatic life, commercial shellfish harvesting, fishing, recreation, agriculture and water supply. Wetlands provide stormwater and flood storage, recharge of groundwater reservoirs, filtration and storage of sediments, nutrients and other pollutants, shoreline protection and habitat for aquatic organisms and wildlife.

Activities associated with the exploration and production of wells for oil and gas can result in stream and wetland impacts similar to any construction and development project. Well site development involves a range of infrastructure including drilling pads, reserve and mud pits, freshwater ponds, flowback water ponds, access roads, dikes, berms, equipment ramps, borrow pits, disposal areas, staging areas, water lines, gathering lines and gas transmission pipelines. As in any construction project, stream and wetland impacts occur most commonly from the placement of material in a stream or wetland to support a structure (such as a culvert or road crossing), damming of a stream channel to create a pond or lake, disturbance to the bottom or sides of a stream (e.g. streambank stabilization) or filling or draining of wetlands.

If a gas exploration or production activity requires a federal permit under Section 404 of the Clean Water Act because of impacts to a stream or wetland, it also requires a certification that the project will be consistent with state water quality standards. The certification is commonly called the 401 Certification by reference to the section of the Clean Water Act that created the certification requirement. The Water Quality Certification (WQC) program in DENR's Division of Water Quality provides the review required for issuance of a Section 401 Certification. To receive a 401 Certification, the applicant must show that:

- No practical alternative exists to the stream or wetland impacts.
- The stream and wetland impacts have been minimized.
- Mitigation has been provided for stream and/or wetland impacts.

- The project does not degrade groundwater or surface waters.
- The project does not result in cumulative impacts that cause or will cause a violation of downstream water quality standards.
- The project provides protection of downstream water quality standards through the use of on-site stormwater control measures.

Environmentally sensitive site design

Appropriate selection and design of the well site can be a major tool in the protection of North Carolina's streams, rivers and lakes. With respect to gas production, major site location selection criteria will clearly involve geology of the site and commercial viability, but environmental considerations also have a role in siting and designing production-related infrastructure. Potential operators might consider the following factors:

- Are nearby surface waters especially particularly sensitive? Examples might be waters classified for drinking water supply or carrying an outstanding resource water designation.
- Are nearby or downstream waters the home of any threatened or endangered species?
- Is the topography surrounding the proposed well pad conducive to the construction of measures for effective control of runoff?
- Are there wetlands or buffers nearby that require particular attention in siting infrastructure?
- Can the well site accommodate any necessary setbacks? For example, oil and gas programs in other states include separation or setback requirements from a variety of features including water supply watershed boundaries, water supply wells, creeks and rivers, wetlands and floodplains. Separation criteria can be especially effective in addressing the pollutants conveyed in stormwater runoff.

Once a site location has been selected, environmentally sensitive site design will include the structural stormwater control measures necessary to protect surface waters from the pollutants, sediment and increased flow volume generated by activities at the well pad. These measures should be designed to control the following sources of potentially problematic stormwater runoff constituents:

- Sediment from site grading and subsequent well pad erosion;
- Subsoil and topsoil stockpiles;
- Initial drilling fluids, muds and cuttings;
- Fuel and petroleum products, as well as petroleum hydrocarbons originating down hole;
- Equipment wash water, detergents and solvents;
- Proppants and hydraulic fracturing fluids with known and unknown constituents;
- Produced water;

- Increased runoff volume

Stormwater management measures should also acknowledge the importance of operating practices and sequence of activities on the well pad. During site development there can be intense activity, conducted 24 hours per day. Site clearing and grading, mobilization and set up, hydraulic fracturing and re-fracturing, and demobilization all represent stages of activity similar to the most intense construction and industrial activities. During these times of focused, intense activity, management actions can increase, or decrease, the risk of discharge of stormwater pollutants.

Even during the less intense periods of production, or of stand-by or close out or capping, when the risks are less there is still a need for evaluation of the character of the risks, and of appropriate preventive measures and operating practices.

Surface spills and releases from the well pad

At similar industrial sites, standard good practice requires the development of a written site-specific spill plan including plan elements addressing on-site spill response equipment, personnel training, identification of on-site personnel in charge of executing the spill plan, immediate action in the form of containment, control and countermeasure responses, and reporting to environmental authorities. The purpose of rapid clean-up is, in part, to prevent the transport of any spilled material into nearby waterways by stormwater runoff. No federal regulations require hydraulic fracturing operations to have a comprehensive spill plan to address the several different types of fluids potentially on site, but a number of state oil and gas programs require operators to have an emergency response plan.

A rain event concurrent with a spill may transport pollutants directly to a receiving water, leaving little time to react to the spill. Effective response actions may be impeded if the spill occurs during a heavy rain.

Spills and releases during transportation and storage

As with transportation of any fluids or wastes, the transport of hydraulic fracturing chemicals, drilling muds, flowback water and other wastes associated with oil and gas exploration and production present the risk of spills or leaks from truck accidents or pipeline leaks. The magnitude of truck traffic necessary to support hydraulic fracturing increases the risk of spills from truck accidents. This risk could be reduced by relying instead on pipelines for transport of water and wastewaters, but pipelines still may leak or rupture if not adequately constructed or maintained. The environmental impacts of such spills vary based on the type and volume of fluid spilled, the accessibility of the site to emergency response crews, and the preparedness of the emergency response crew to deal with the particular substance that is spilled. There is obvious concern with spills of diesel fuel, hydraulic fracturing additives and wastewaters, but less obvious issues include spilling untreated raw water into pristine high quality waters, such as an example cited by Pennsylvania officials of spillage of water from the Susquehanna River into a headwater trout stream.[187]

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[187] Pennsylvania Department of Environmental Protection, personal communication, February 3, 2012.

Potential public health impacts

Stormwater pollution can impact public health through a limited number of mechanisms. Stormwater discharges polluted with carcinogens or toxics can accumulate in the tissue of fish and shellfish, and can be passed on to humans that consume them. Even less worrisome pollutants like sediment or turbidity can degrade the natural aquatic habitat and make the resident fish susceptible to disease organisms that may be transmitted to humans.

In general, public water supplies are effective at providing clean potable water and incidents of human impacts from public water supplies are rare. However, increased pollutant content in the raw water source could increase treatment costs for the public utility. Potential impacts to public water supply are addressed more fully in Section 3.A of this report.

Conclusions related to surface water impacts and stormwater management

We recommend conducting baseline data collection for surface waters. DENR should collect pre-drilling surface water monitoring data for areas proposed for drilling to establish baseline water quality information. The extent and location of data collection should be determined as drilling blocks are established.

The impacts of stormwater discharges from oil and gas exploration and production are substantially similar to the impacts from the construction and industrial activities that occur in North Carolina today. Oil and gas exploration and production can disturb large areas of land to develop impervious well pad sites, creating significant impacts related to sedimentation and erosion, water quality pollution, increased peak discharges, increased frequency and severity of flooding, and other stormwater concerns.

However, unlike existing construction and industrial activities, oil and gas exploration and production activities are exempt from the requirements of the National Pollutant Discharge Elimination System (NPDES) stormwater permit program under the federal Clean Water Act unless there has been a documented water quality standard violation, or release of a reportable quantity of oil or hazardous substance. Since North Carolina has relied on the federal stormwater permitting programs to manage industrial stormwater impacts, the state is not prepared to effectively manage stormwater impacts associated with oil and gas production.

We recommend that the General Assembly authorize a state stormwater regulatory program for oil and gas activities, including requirements for stormwater permitting, inspections and compliance activities.

F. Land application of oil and gas wastes

As previously noted, 15A NCAC 2T .0113(a)(10) provides an exemption from regular permitting for land application of "drilling muds, cuttings and well water from the development of wells or from other construction activities including directional boring." While this exemption was intended to address these wastes generated by water well construction and utility borings, it is written in such a way that it would allow essentially unregulated disposal of these wastes from any type of well, and could even be construed to pertain to horizontal drilling of gas wells.

If natural gas extraction and production occurs in North Carolina, we recommend that the General Assembly prohibits land application of solid waste and wastewater from oil and gas activities because of the environmental impacts and the lack of sufficient capability to dispose of all waste generated.

G. Air quality impacts

A variety of processes and equipment used in oil and gas extraction and production can have air quality impacts. Air emissions associated with oil and gas activities may include a number of potential contaminants with differing health and environmental consequences. The air quality impacts of an oil and gas operation will depend on a number of different factors, including: the specific type of air contaminants emitted; the volume of those emissions; the siting of the operation; and the geography and meteorology of the area.[188]

Air emissions, including fugitive emissions and flaring

Air contaminants (commonly referred to as air pollutants) are classified and regulated based on the physical state of the pollutant and the effect the pollutant has on human health and the environment. Four general classifications of pollutants have been established by the federal Clean Air Act and generally adopted by the states: criteria pollutants, toxic pollutants (also known as hazardous air pollutants or HAPs); other Clean Air Act (CAA) regulated pollutants; and greenhouse gases (GHG). The classifications are spelled out in more detail in the lists and discussion below.

- Criteria Pollutants
  - Particulate matter (PM-10 and PM-2.5)
  - Carbon monoxide (CO)
  - Sulfur dioxide (SO_2)
  - Nitrogen oxides (NO_x)
  - Ozone
  - Lead (Pb)
- Hazardous Air Pollutants (HAP)
  - Organic pollutants, including dioxins and furans
  - Inorganic pollutants, including metals
  - Acid gases
- Other CAA Regulated Pollutants
  - Volatile organic compounds (VOC)
  - Fluorides
  - Sulfuric acid mist (H_2SO_4)
  - Reduced sulfur compounds (including hydrogen sulfide (H_2S))
- Greenhouse Gases (GHG)

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[188] This section of the report analyzes the potential impacts of hydraulic fracturing based on North Carolina's air quality program; there can be considerable variations between state programs.

- Carbon dioxide (CO_2)
- Nitrous oxide (N_2O)
- Methane
- Hydrofluorocarbons
- Perfluorocarbons
- Sulfur hexafluoride (SF_6)

Criteria Pollutants

Criteria pollutants (listed above) are the pollutants for which National Ambient Air Quality Standards (NAAQS) have been established. Federal rules, adopted by the U.S. Environmental Protection Agency (EPA), set the NAAQS at ambient air concentrations that are generally accepted to be protective of human health and the environment.[189] Several different regulatory tools are used to achieve the NAAQS. At the state level, the Clean Air Act requires development of a state implementation plan (SIP) for achieving the standard for each pollutant. The SIP typically includes emission standards for sources that emit the particular criteria pollutant, but may also include other measures.[190] EPA also sets federal New Source Performance Standards (NSPS) for new, modified or expanded sources of a criteria pollutant and the state implements New Source Review (NSR) permitting requirements for those sources.

Hazardous Air Pollutants

Hazardous air pollutants (HAPs) have acute, chronic and carcinogenic toxic effects on human health. The HAPs regulated under federal rules are listed in Section 112(b) of the Clean Air Act. The North Carolina air quality program enforces the National Emission Standards for Hazardous Air Pollutants (NESHAP) with respect to sources in North Carolina. The national emissions standards apply only to the types of sources specifically listed for regulation under Section 112 of the Clean Air Act and do not apply to every potential source of hazardous air pollutants. The national standards are technology based – that is, each standard identifies specific air pollution control technology or level of control required for that particular type of pollution source; the technology selection then determines the emissions limits that go into the air quality permit.

DAQ also addresses many of the federally listed hazardous air pollutants (and additional toxic air pollutants that are regulated only by the state) under state-adopted acceptable ambient level (AAL) guidelines. The guidelines have been developed based on exposure effects on human health. The state program to control toxic air pollutants requires a demonstration that toxic air emissions above a certain emission rate will not exceed the acceptable ambient level at the property boundary of the facility or operation.

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[189] Criteria pollutants are also frequently used as surrogates for hazardous air pollutants (HAPs); for example, controlling particulates can provide reductions in emissions of metals and controlling volatile organic compounds (VOCs) can provide reductions in organic HAP emissions.

[190] Under some circumstances (including state failure to develop an approvable plan), EPA can develop a federal implementation plan (FIP) for a state.

Other CAA regulated pollutants

Other CAA regulated pollutants are primarily regulated through the Best Achievable Control Technology (BACT) component of the NSR permitting program although some of these pollutants are regulated by specific NSPS. More discussion about BACT is presented under NSR permitting.

Greenhouse gases

Greenhouse gases (GHG) are somewhat unique in that the gases were not listed as pollutants under the Clean Air Act or its implementing regulations until EPA adopted New Source Review (NSR) rules for GHGs in June of 2010. The rulemaking followed an EPA finding that Greenhouse Gases in the atmosphere endanger both the public health and the environment for current and future generations.[191] The Title V permitting requirements from the Clean Air Act Amendments (CAAA) of 1990 would ultimately be used to enforce the GHG emission limitations developed under the NSR program.

Emission sources associated with natural gas extraction and production

A variety of emission source types can be associated with natural gas, from exploration through production. Many of these sources are reciprocating internal combustion engines (RICE) or combustion turbines (CT) for producing electricity or operating drilling equipment. During production of the natural gas, these emission sources power pumps and compressors to process the gas to pipeline quality. The production process also involves the use of glycol dehydrators, compressors, storage vessels and other equipment that may emit air pollutants. In addition to the production equipment, emission sources associated with hydraulic fracturing would include the fracturing chemicals, mobile sources (trucks and other heavy equipment) and methane (a powerful GHG) that may escape from the wells.

As various states have addressed natural gas activities, several have estimated emissions coming from the operations. The New York Department of Environmental Conservation developed a draft generic environmental impact statement (GEIS) for natural gas drilling in the Marcellus Shale, and revised the GEIS several times in response to a series of public comment periods. The GEIS estimated potential emissions from the different stages of gas production and the potential impact on compliance with national ambient air quality standards and state toxic standards. The New York GEIS concludes that additional pollution controls may be necessary for the diesel completion equipment engines and the older tier drilling engines in order to comply with the 24-hour fine particulate (PM2.5) standard and the 1-hour NO2 standard. Particulate traps can be used to reduce PM2.5 emissions; selective catalytic reduction reduces NO2 emission.

The GEIS also estimates that statewide NOx emissions could be increased by 3.7 percent from the hydraulic fracturing operations and as much as 10.4 percent in the upstate area where the Marcellus Shale is located. These increases in NOx emissions raise concerns for the impact on

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[191] EPA's authority to make the endangerment finding – a necessary precondition for regulation under the Clean Air Act --was upheld by the United States Supreme Court in *Massachusetts* v. *EPA,* 549 U.S. 497 (2007).

ozone concentrations and the state's ability to attain and maintain compliance with the federal ozone standard.

Pennsylvania is in the process of collecting 2011 emission data from the owners and operators of natural gas production and processing operations in unconventional shale formations across the state. The emission data was due to the Pennsylvania Department of Environmental Protection by March 1, 2012. The emission data will become part of the state's comprehensive emission inventory due to EPA by Dec. 31, 2012. These and other efforts will provide North Carolina with valuable information for understanding the potential emissions from natural gas production activities and the impact of those emissions on air quality in the state.

Emissions and regulatory applicability

Combustion sources, such as reciprocating internal combustion engines and combustion turbines, are sources of criteria pollutants, hazardous air pollutants, greenhouse gases and potentially sulfuric acid mist. As a result, both source categories are covered by various emissions standards under the state implementation plan or SIP (which sets out the state air quality standards necessary to meet national ambient air quality standards); federal new source performance standards; state and federal requirements for sources of toxic air pollutants; and other federal engine standards. Standards applicable to an operation requiring new source review permitting are discussed below.

Natural gas production operations, including those listed below, are primarily regulated by federal new source performance standards (NSPS) and national emissions standards for hazardous air pollutants (NESHAP). In 1985, EPA set new source performance standards for emissions of volatile organic compounds (VOCs) and sulfur dioxide from natural gas processing facilities. EPA only recently proposed new source performance standards for other oil and natural gas operations. On Aug. 23, 2011, EPA proposed new source performance standards for emissions of volatile organic compounds (VOCs) and sulfur dioxide from a broader range of oil and natural gas exploration and production activities. As proposed, the standards would include operational requirements for completion of hydraulically fractured natural gas wells. EPA originally proposed to adopt a final NSPS rule by Feb. 28, 2012, but extension of the original comment period has delayed action beyond that date. [192] Affected sources include: gas wellheads, centrifugal compressors, reciprocating compressors, pneumatic controllers, storage vessels and sweetening units. Until the proposed rules go into effect, no federal new source performance standards apply to emissions from these natural gas exploration and production activities.

The amended NESHAP, 40 CFR Part 63, Subpart HH, regulates hazardous air pollution emissions from "Oil and Natural Gas Production Facilities." Affected facilities include, among others: glycol dehydration units, storage vessels with the potential for flash emissions, and compressors intended to operate in volatile HAP service.

[192] Federal Register /Vol. 76, No. 163 /Tuesday, August 23, 2011 / Proposed Rules p. 52799

Many of the chemicals used in the production of natural gas from hydraulic fracturing are proprietary, but may include VOC and volatile HAP. Currently, there are no federal or state regulations for the control of VOC or volatile HAP from hydraulic fracturing chemicals.

Methane is the primary component of natural gas and burns cleaner than other fossil fuels, producing lower levels of greenhouse gases such as CO_2. Although CO_2 emissions may be lower, methane is four times more powerful than CO_2 as a GHG. There are no federal or state regulations for the control of methane or other GHG from wells or other gas leaks with the exception of Prevention of Significant Deterioration (PSD) permitting requirements that may apply.

Mobile sources

An increase in heavy-duty truck traffic is associated with many stages of natural gas production. The increased truck traffic results in higher NOx, VOC and PM2.5 emissions in the area near the operation. In the New York GEIS, the conclusion was that the resulting increase was less than 1 percent over the baseline emissions. States generally have limited control over emissions from on-road mobile sources. Typically USEPA sets fuel efficiency and emission standards for on- and off-road engines. North Carolina does have anti-idling and fugitive dust regulations that may apply to vehicle operations at a natural gas exploration and production site. Also, in the event that NSR permitting is required, emissions from mobile sources may have to be considered.

Air quality permitting requirements

Air quality permitting in North Carolina is a combination of state and federal requirements. The North Carolina Division of Air Quality (DAQ) has delegated authority to issue air quality permits under the federal Clean Air Act. As a result, most air quality permits issued by DAQ are federal permits that can be enforced by the state and U.S. EPA. The exceptions would be permits issued under state-only requirements such as the state air toxics rules, odor control standards and open burning regulations.

State-only permits

Facilities that are classified as small or synthetic minor based on their potential to emit criteria pollutants or hazardous air pollutants obtain state-only construction and operation permits.

In this case, the terms “small” and “synthetic minor” refer to the facility’s classification by reference to permitting requirements under Title V of the Clean Air Act. Under Title V, major air pollution sources require a federal operating permit; a source is generally considered a major source if it emits 100 tons per year (tpy) of a criteria pollutant and 10/25 tpy of individual/aggregate HAP emissions. Small facilities are those that do not have the potential to emit air pollutants over the major source thresholds. Synthetic minor facilities take permit restrictions to limit emissions below the Title V major source thresholds. The permit restrictions can include limits on annual hours of operation or volumes of production, types and/or quantities of fuels burned, or raw materials, among others. Without those limits, the facility would be a major source under the Title V permitting program. The state-issued permits can include SIP or federal emission control requirements for criteria pollutants or hazardous air pollutants as well as state-only enforceable requirements.

Title V Operating Permits

The Clean Air Act amendments of 1990 established a new federal operating permit program for major sources. Facilities permitted under the Title V program go through a higher level of public and U.S. EPA oversight as compared to state-only permits. The Title V permitting program was intended to consolidate all Clean Air Act requirements in one document. The permits can include state and federal emission control requirements for criteria pollutants or HAPs. In North Carolina, Title V operating permits also include state-only requirements that can only be enforced by the state. Permit conditions related to control of criteria pollutants or federally regulated HAPS can be enforced by both the state and EPA; conditions based on state-only requirements are only enforced by the state. In the oil and gas sector, a Title V permit would only be required for a natural gas processing facility (if it is a major source).

New Source Review Permits

New Source Review (NSR) permits are issued to major sources or for major modifications to an existing source. The NSR permitting program was an original part of the Clean Air Act and applies differently depending on whether the proposed project will be located in an area designated as attainment or non-attainment for any given criteria pollutant. A non-attainment designation means the area is out of compliance with one of the national ambient air quality standards.

In attainment areas, Prevention of Significant Deterioration (PSD) permits are issued for the purpose of maintaining the attainment status of the area. This goal is achieved using two primary tools: best available control technology (BACT) requirements and ambient air quality analyses.

BACT is defined as:

> "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant."[193]

Air quality analyses are performed on the proposed facility or modification to estimate the increase in the ambient concentration of criteria pollutants with the goal of protecting the attainment status of the area where the proposed facility would be located. The analyses use state-of-the-art air dispersion models, predicted emission rates and actual meteorological data and terrain conditions. In certain circumstances, air quality analyses are required for visibility impacts in areas such as national parks and wilderness areas.

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[193] USC Title 42, Section 7479, Paragraph (3)

In non-attainment areas, Non-attainment Area New Source Review (NAA NSR) permits are issued for the purpose of improving the air quality in the non-attainment area. This goal is also achieved using two primary tools: lowest achievable emission rate (LAER) and emission offsets.

LAER is defined as:

> "(A) the most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or (B) the most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent."[194]

Emission offsets are reductions in emissions of the limiting pollutant that are used to offset the increased emissions of a new or modified facility. Emissions offsets are typically generated in the non-attainment area in which the proposed facility would be located. Emission offsets are usually greater than the anticipated increase from the proposed facility or modification. Offsetting emissions reductions can be obtained from the facility requesting modification or from reductions at other facilities in the area.

As noted above, EPA has only recently proposed new source performance standards for sources related to natural gas exploration and development, including hydraulic fracturing. Until those standards become final, only natural gas processing facilities have a new source performance standard. Air emissions from the currently unregulated sources associated with natural gas production may, however, affect the permitting of other industrial facilities in the Triassic Basin counties if those sources affect the area's ability to attain an air quality standard.

There are currently no non-attainment areas in the airshed of the Triassic Basin. However, the 2012 attainment designations for ozone are based on the current ozone standard of 75 ppb. EPA undertook a review of that standard two years ago with the intent of potentially adopting a lower, more protective value. The national Clean Air Scientific Advisory Committee has recommended a more restrictive standard in the range of 60-70 ppb. The Clean Air Act requires EPA to review the national ambient air quality standards every five years; the ozone standard is due for review in 2013 and a final EPA decision is expected in 2014.

If EPA accepts the committee's recommendation and adopts a new ozone standard within the 60-70 ppb range, much of the area in the Triassic Basin could be designated non-attainment for ozone. Areas that have previously been designated non-attainment include all or part of Wake, Durham, Orange and Chatham counties. Since the ozone standard is based on an eight-hour average, even short term increases in NOx emissions in these areas could contribute to an increase in ozone formation and future non-attainment designations.

North Carolina will be able to learn from other states that have experience with issuing air quality permits for sources related to exploration and production of oil and gas. For example, Ohio Environmental Protection Agency issued a final general air quality permit for production

[194] USC Title 42, Section 7501, Paragraph (3)

operations at shale gas well sites in Ohio. The general permit covers a variety of emissions sources found at most shale gas well sites, including internal combustion engines, generators, dehydration systems, storage tanks and flares. It contains emissions limits, operating restrictions and monitoring, testing and reporting requirements. Applicants have to meet the criteria of the general permit in order to qualify for this streamlined permitting approach.

Potential public health impacts

The air quality standards enforced by the North Carolina Division of Air Quality are health-based standards. As mandated by the Clean Air Act, EPA sets national ambient air quality standards at levels considered to be protective of human health. Although the federal hazardous air pollution standards are technology-based emission standards, Section 112 of the Clean Air Act Amendments of 1990 requires EPA to evaluate the residual health risk after the technology standards have been met. Many natural gas production activities have been exempt from federal hazardous air pollutant and NSPS standards, however, and EPA has only recently proposed rules to apply to those activities. Until EPA finalizes the standards proposed in August 2011, those activities continue to be exempt from federal standards.

Limited ambient air monitoring has been conducted near natural gas operations. The Arkansas Department of Environmental Quality did conduct limited monitoring in the Fayetteville Shale region of northeastern Arkansas. The study concluded that concentrations of NOx were not measured above the instrument's detection level. The monitoring did not result in VOC concentrations above the instrument's detection level at natural gas well sites or compressor stations. However, daily average and 15-minute rolling average concentrations of 678 ppb and 5,321 ppb, respectively were observed near the drilling sites. The study recommended that future monitoring studies use instruments with lower detectible limits, and instruments that can measure individual VOC compounds.

The North Carolina toxic air pollution program uses acceptable ambient levels (AALs) established by the North Carolina Scientific Advisory Board to ensure that emissions of toxic air pollutants have no long-term health consequences. A source must demonstrate that the AALs are met at the property boundary to prevent adverse health impacts to people occupying or using nearby property. With the exception of internal combustion engine standards, the state air toxics standards will be the only air quality rules that apply to many natural gas production activities, at least until EPA finalizes the proposed NSPS and HAP rules for natural gas production.

Conclusions related to air quality impacts

Natural gas production presents some unique challenges, given the way the state air toxics program has been implemented in North Carolina. As mentioned above, the program requires a source of state-regulated toxic air pollutants to demonstrate compliance with the AALs at the property boundary. Shale gas production often occurs under a lease of property that may be owned and in some cases occupied by another person. If natural gas production occurs on a residential property or farm, the property owner or occupant may be exposed to unhealthy concentrations of toxic pollutants. An evaluation of the existing policy will be necessary to determine whether it represents adequate protection under scenarios where natural gas production is occurring on residential properties or farms.

We also recommend that DENR collect pre-drilling air emissions data for areas proposed for drilling, at a distance determined through additional research.

H. Impacts on fish, wildlife and important natural areas

Research on the potential impacts of natural gas extraction and production in the Triassic Basins (including the Dan River Basin and the Deep River Basin) of North Carolina on fish, wildlife, and important natural areas is limited. Although significant knowledge gaps exist, scientists have begun to study the issue. The potential impacts range from contact with hydraulic fracturing fluids and wastewater to forest fragmentation and sedimentation of surface waters.

This section begins with descriptions of the important lands and species of the area underlain by the Triassic Basins, followed by the potential impacts posed to these natural resources of the state by oil and natural gas exploration and production.

Publicly owned lands in North Carolina's Triassic Basins

Significant natural areas throughout the Triassic Basins are owned by the state, the federal government and local governments. Governments maintain these properties to provide recreation areas for the public, to conserve sensitive natural lands and species, and to provide the ecological benefits associated with forests, green space and clean water. In addition to the publicly owned lands described here, there are additional natural areas owned by public organizations that may not be represented here, such as city parks, that provide ecological benefits but are not captured within this dataset. One example of a land not included in this dataset is the 14,000 acres of land around Harris Reservoir owned by Progress Energy. Although this land is in private ownership, Progress Energy permits public access for hunting. It would be difficult to capture a complete list of such privately owned lands, but it is important to note that these types of privately owned lands can provide both recreational and ecological benefits that could be impacted by natural gas extraction and production.

The U.S. Army Corps of Engineers owns two key pieces of land in the area underlain by the Triassic Basins: Jordan Lake and Falls Lake. The N.C. Wildlife Resources Commission manages lands adjacent to the two reservoirs as part of the Game Land Program. These reservoirs and the surrounding properties provide recreational activities such as boating, swimming, fishing, biking, camping and hiking. The reservoirs also supply water for neighboring communities, aid in flood and water quality control and provide habitat for fish and wildlife. Other significant natural areas in the Triassic Basin include the Pee Dee National Wildlife Refuge and a part of the Uwharrie National Forest (located in the Wadesboro Sub-basin of the Deep River Basin).

State-owned lands have been acquired to conserve and protect examples of the natural beauty, ecological features and recreational resources of statewide significance, to provide outdoor recreational opportunities in a safe and healthy environment, and to provide environmental education opportunities that promote stewardship of the state's natural heritage. In addition to state parks, state-owned lands in the Triassic Basins include lands owned by University of North Carolina - Chapel Hill and two National Historic Landmarks: Duke Homestead and Town Creek Indian Mound. National Historic Landmarks are nationally significant historic places designated by the Secretary of the Interior of the United States because they possess exceptional value or quality in illustrating or interpreting the heritage of the United States.

Local governments conserve lands for the same reasons as state governments. Wake and Durham counties have open space lands in the Durham Sub-basin of the Deep River Triassic Basin. Wake County's Lake Crabtree County Park is also in the area.

Lands owned by local, state or federal governments within the Dan River Basin, the northern portion of the Deep River Basin, and the southern portion of the Deep River Basin are shown in the next three figures.

Figure 4-2. Publicly Owned Lands in the Dan River Triassic Basin

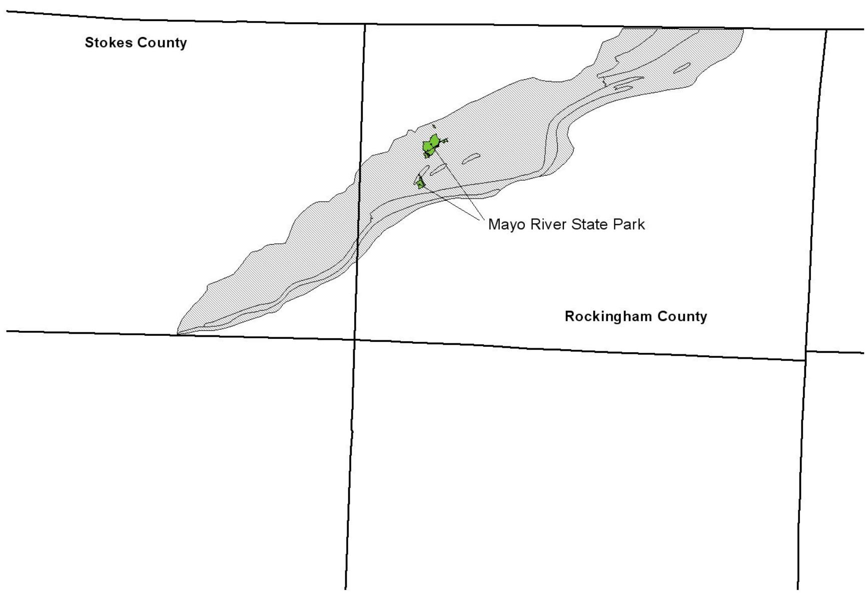

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Figure 4-3. Publicly Owned Lands in the Northern Portion of the Deep River Basin

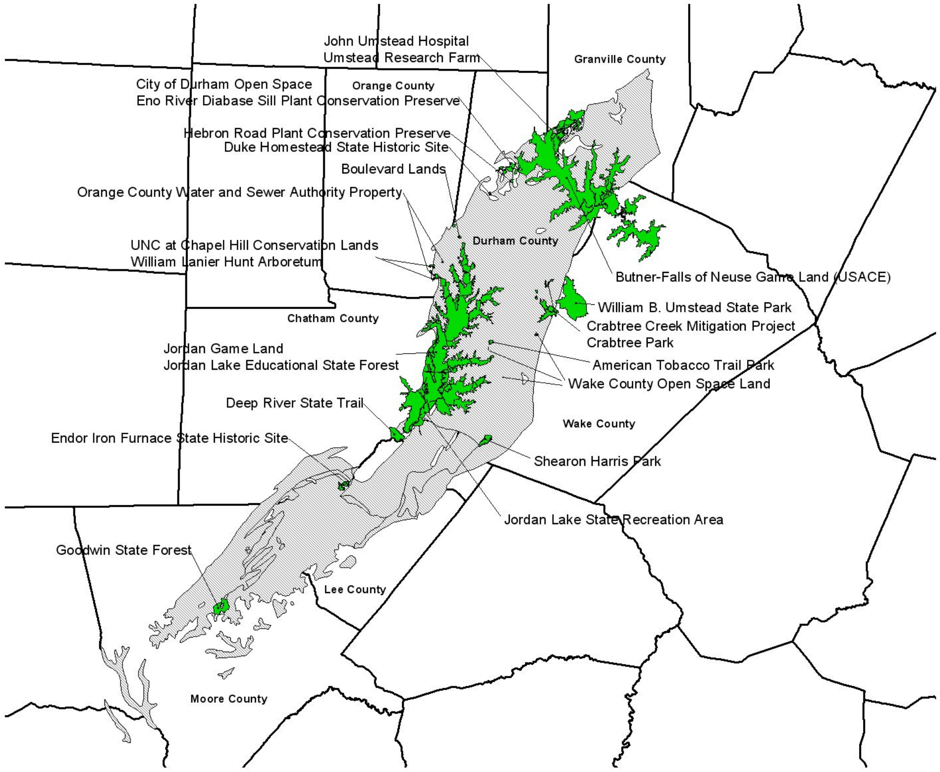
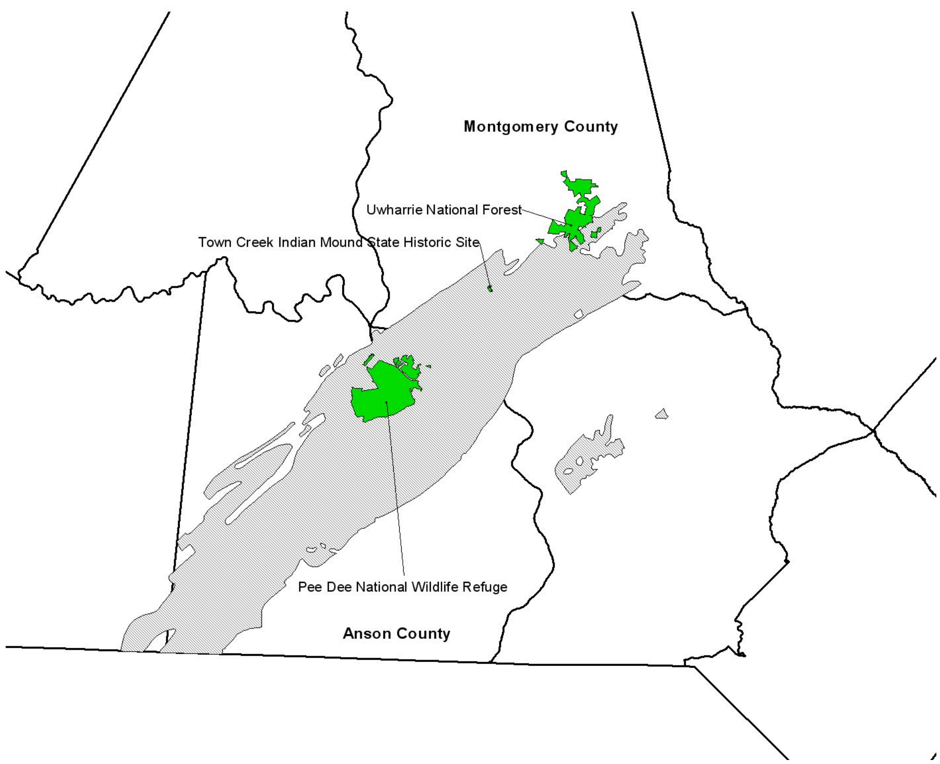


Figure 4-4. Publicly Owned Lands in the Southern Portion of the Deep River Basin



Important natural areas of North Carolina's Triassic Basins

The North Carolina Natural Heritage Program inventories, catalogues and supports conservation of the rarest and most outstanding elements of the natural diversity of North Carolina. These include rare plants and animals and significant natural areas that merit special consideration as land-use decisions are made. Information collected by the Natural Heritage Program allows government agencies and private developers to make better decisions about project siting and design. The information also helps public and private agencies set priorities for acquisition of conservation lands.

Significant Natural Heritage Areas

A significant Natural Heritage Area (SNHA) is an area of land or water identified by the Natural Heritage Program as being important for conservation of the state's biodiversity. SNHAs contain one or more natural heritage elements: high-quality or rare natural communities, rare plant or animal species and special animal habitats. Designation as an SNHA does not provide legal protection or prevent natural gas exploration and production from occurring within these sites.

SNHAs are rated based on the value of the natural heritage elements found there; significance is rated based on the rarity and quality of those elements in comparison with other sites. SNHAs are designated as significant at the national, regional, state or county level using parameters developed by the Natural Heritage Program, NatureServe and The Nature Conservancy to measure statewide and global rarity for rare species and communities. These definitions are shown in Table 4-5.

Table 4-5. Definitions for SNHA Significance Rankings

Rank	Natural Area Significance
A	**Nationally** significant natural areas contain examples of natural communities, rare plant or animal populations, or geologic features that are among the highest quality, most viable, or best of their kind in the nation, or clusters of such elements that are among the best in the nation.
B	**Statewide** significant natural areas contain similar ecological resources that are among the best occurrences in North Carolina. There are a few better quality representatives or larger populations on nationally significant sites elsewhere in the nation or possibly within the state.
C	**Regionally** significant natural areas contain natural elements that may be represented elsewhere in the state by better quality examples, but which are among the outstanding examples in their geographic region of the state. A few better examples may occur in nationally or state significant natural areas. Regions consist of an area the size of about five counties.
D	**County** significant natural areas contain exemplary instances of high quality community types that are either common or at least fiarly widespread in this region, or sites that serve as important wildlife habitat. These sites are considered important for local conservation based on size and integrity of the site, maturity and diversity of the commuity, and lack of distubance/fragmentation. Sites important for wildlife habitat are also connected by corridors of continuous forest habitat, and are thus part of a network of wildlife habitats extending through the landscape.

Of the 129 SNHAs identified within the Triassic Basins, 12 are of national significance based on the importance of the area for rare species and high quality aquatic habitat. Thirty-five SNHAs have state significance; an additional 35 have regional significance and 47 are significant at the county level. SNHAs that are partially or wholly within the Triassic Basins are shown by rank in the following tables.

Table 4-6. Nationally Significant Natural Heritage Areas within the Triassic Basins (Rank A)

Site Name	Acreage	Ownership
Beaver Pond Road Longleaf Pine Forest	83.37	Federal
Catsburg Natural Area	110.15	Federal, Private
Dan River Aquatic Habitat	1,240.27	Public Waters
Eno River Diabase Sill	44.49	State
Knap of Reeds Creek Diabase Forest and Glades	162.56	Federal, State
Knap of Reeds Creek Diabase Levee and Slopes	136.09	Federal, State
Lower Brown Creek Swamp	2,023.00	Federal, Private
Lower Rocky River/Lower Deep River Aquatic Habitat	396.72	Public Waters
Mayo River Aquatic Habitat	207.06	Public Waters
Middle Deep River Aquatic Habitat	1,451.25	Public Waters
Picture Creek Diabase Barrens	407.35	State, Private
Upper Tar River Aquatic Habitat	257.87	Public Waters

Table 4-7. Statewide Significant Natural Heritage Areas within the Triassic Basin (Rank B)

Site Name	Acreage	Ownership
Beaverdam Lake Swamps and Arkose Outcrops	899.17	Federal, Private
Bennett Bridge Diabase Dike	4.05	Federal
Big Oak Woods	56.57	State
Cedar Mountain	141.29	Private
Cheek Creek Ridge	34.01	Federal
Diabase Sill Near Clay	540.03	Private
Drowning Creek Aquatic Habitat	180.05	Public Waters
Endor Iron Furnace Natural Area	253.61	State
Fitzgerald Woodland	88.36	Private
Flat River Bend Forest	17.41	Federal
Grassy Islands/Smith Lake	2,242.43	Private
Griffen Hunt Preserve	6.53	State, Private
Gulf Diabase Forest	6.83	Private
Haw River Dicentra Slopes	15.94	Private
Hebron Road Remnant Glade	90.11	State, Private
Jacobs Creek Slopes	14.51	Private
Jordan Lake Bald Eagle Habitat	5,995.28	Federal, State
Lake Rogers Diabase Area	13.13	State, Private
Lick Creek Bottomland Forest	1,743.79	Federal
Lower Little River (Montgomery) Aquatic Habitat	116.36	Public Waters
Lower Little River (Richmond) Corridor	1,703.65	Private
Lower New Hope Creek Floodplain Forest and Slopes	1,422.76	Federal, Private
Mason Farm/Laurel Hill Oak-Hickory Forest	447.43	State
Mayodan Bluffs	47.99	Private
Morgan Creek Bluffs	189.20	State, Private
Morgan Creek Floodplain Forest	1,537.86	Federal, Private
Mountain Creek Corridor	1,804.97	Private
Naked Creek Aquatic Habitat	62.89	Public Waters
New Hope Creek Aquatic Habitat	32.86	Public Waters
New Hope Creek Bottomland Forest	964.59	Federal
Northside Diabase Area	1.90	Federal
Redwood Road Remnant Glade	22.48	Federal
South Butner Diabase Swamp	99.19	State
Upper Brown Creek Swamp	3,036.51	Private
William B. Umstead State Park	5,578.80	State

Table 4-8. Regionally Significant Natural Heritage Areas within the Triassic Basin (Rank C)

Site Name	Acreage	Ownership
Bear Slide Bluff	12.01	State
Big Beaver Island Creek Slopes	26.09	Private
Cabin Branch Creek Bottomland-Swamp	196.47	Federal
Cape Fear River/McKay Island Floodplain	154.71	Private
Carbonton Diabase Sill	104.48	Private
Deep River Slopes Near Carbonton	44.69	Private
Deep River/Patterson Creek Slopes	74.10	Private
Dry Creek/Mount Moriah Bottomland	438.97	Private
Duke Forest Oak-Hickory Upland	423.32	Private
Gum Springs Church Road Slopes	285.09	Federal
Indian Creek Diabase Slope	16.45	Private
Jenkins Road Diabase Dike	41.33	Federal, Private
Lagrange Diabase Bog	46.52	Private
Leaksville Loam Forests	138.29	Private
Little River Shooting-Star Slopes	109.55	Private
Lower Deep River Slopes	602.20	State, Private
McLendons Creek Diabase Sill and Levees	110.26	Private
Middle Eno River Bluffs and Slopes	2,123.81	State, Local
Middle Pee Dee River Aquatic Habitat	1,459.88	Public Waters
Moncure Boggy Streamheads	269.07	Federal, Private
Northeast Creek Floodplain Forest	819.93	Federal, Private
Northeast Creek/Panther Creek Dikes and Bottomlands	498.66	Federal
Pleasantville Basic Forest	137.01	Private
Polly Branch Slopes	156.64	Federal
Rocky Branch Conglomerate Exposure	60.13	Federal
Rocky Ford Creek Mountain Laurel Bluff	43.29	State
Roundhouse Road Forest	74.63	Private
Savannah Church Diabase Dike	41.19	Private
Smith River Bluffs	20.96	Private
Tar River/Triassic Basin Floodplain	488.99	Private
Thoroughfare Creek Wetlands	201.69	Federal
Upper Drowning Creek Swamp Forest	4,213.34	State, Private
Utley Creek Slopes	459.20	Private
White Oak Creek Floodplain	613.78	Federal
Woodwards Branch Diabase Dike	34.38	Private

Table 4-9. County Significant Natural Heritage Areas within the Triassic Basin (Rank D)

Site Name	Acreage	Ownership
Ash Camp Creek Wetland	53.28	Private
Battle Park	80.77	State
Beaver Creek Floodplain	172.08	Federal, Local
Big Buffalo Creek Galax Slope	20.05	Private
Big Woods Road Upland Forests	1,964.25	Federal, Private
Bush Creek Marshes	216.52	Federal, Private
Candor Lake Slopes and Wetland	28.96	Private
Center Church Headwaters of Little Governors Creek	29.45	Private
Cheek Creek Slope	26.37	Private
Collins Bridge Bluffs	48.60	Private
Cub Creek Bottomlands and Beaver Ponds	103.31	Private
Deep River Bend	22.79	Private
Deep River/Little Governors Creek Forests	91.35	Private
Drowning Creek Slopes	94.29	Private
Dry Fork Pocket Creek Forest	20.81	Private
Falls Lake Shoreline and Tributaries	7,748.07	Private
Gate 4 Mafic Forests	241.28	Private
Harrisville Basic Forest	35.49	Private
Hollemans Crossroads Salamander Pools	3.36	Private
Hollemans Crossroads Slopes	132.37	Private
Jim Branch/Buckhorn Creek Forests	14.56	Private
Kit Creek Slopes and Floodplain	55.36	Federal
Knap of Reeds Creek Beaver Ponds and Swamp	66.69	Federal
Leatherwood Cove	159.02	Private
Little Beaverdam Creek Slopes	95.80	Federal, Private
Little Creek Bottomlands and Slopes	1,447.28	Federal, State, Private
Little Indian Creek Galax Bluff	103.26	Private
Little River (Durham) Corridor	1,185.91	Local, Private
Lower Eno River/Little River Bottomlands	2,157.02	Federal, Private
Middle Lick Creek Bottomlands	1,034.18	Federal, Private
Mills Creek Equisetum Wetland	14.19	Private
New Hope Overlook Bluff and Slopes	405.81	Federal
North Edwards Ridge	119.75	Private
Old Weaver Trail Slopes	317.89	Federal
Parkers Creek Ridges	226.88	Federal
Pee Dee River Skunk Cabbage Seep	145.18	Federal
Pine Hall Slopes	130.37	Private
Poes Ridge/Dam Road Upland Forests	177.61	Federal
Shaddox Creek Swamp	22.62	Private
Shearon Harris Longleaf Pine Forest	356.91	Private
Smith Creek Alluvial Forest and Slopes	479.76	Federal, Private
Stirrup Iron Creek Marsh and Sloughs	217.87	Private
Third Fork Creek Wetlands	144.70	Federal, Private
Town Creek Indian Mound Bottomland	61.22	Private
Town Fork Forest	255.16	Private
Weaver Creek Pine Forest	581.87	Federal
Wide Mouth Creek Conglomerate Exposure	24.10	Private

Significant Natural Heritage Areas within the Triassic Basin are shown in the following maps.

Figure 4-5. SNHAs in the Dan River Triassic Basin

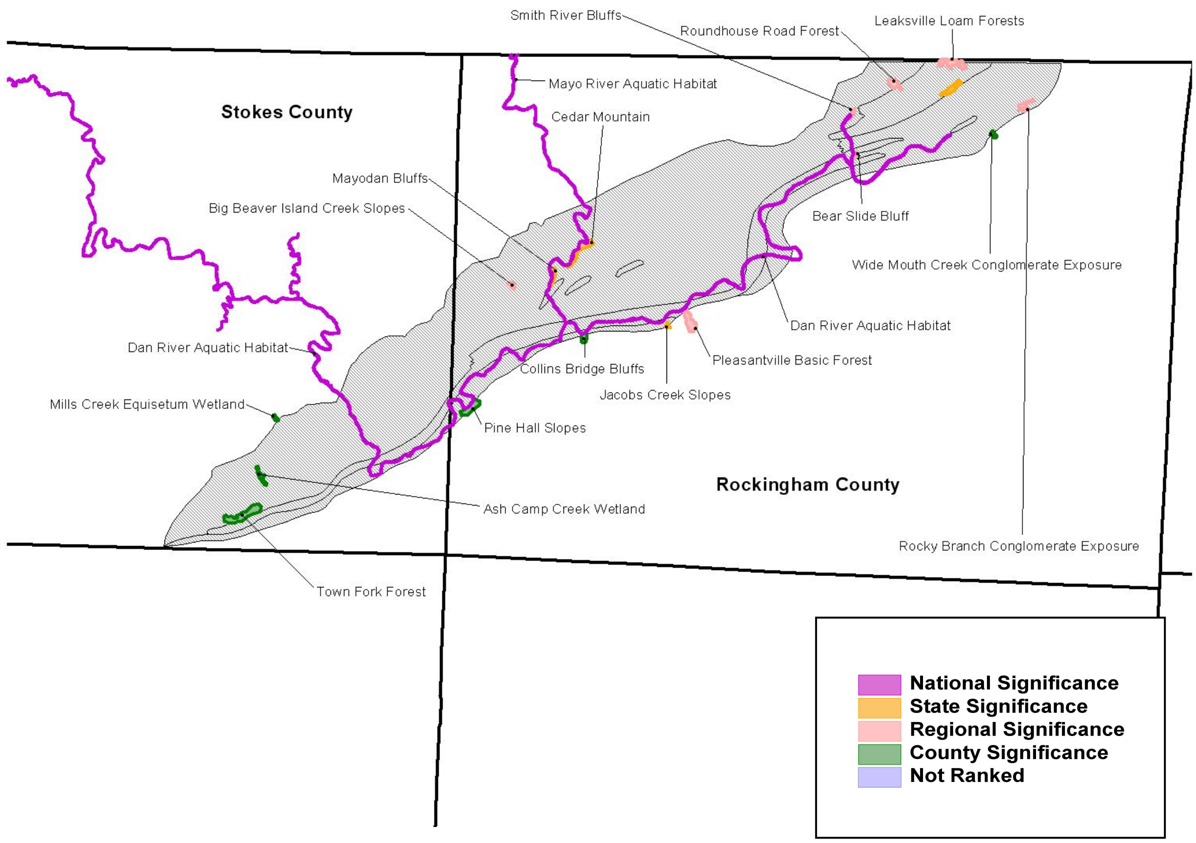


Figure 4-6. SNHAs in the Northern Portion of the Deep River Basin

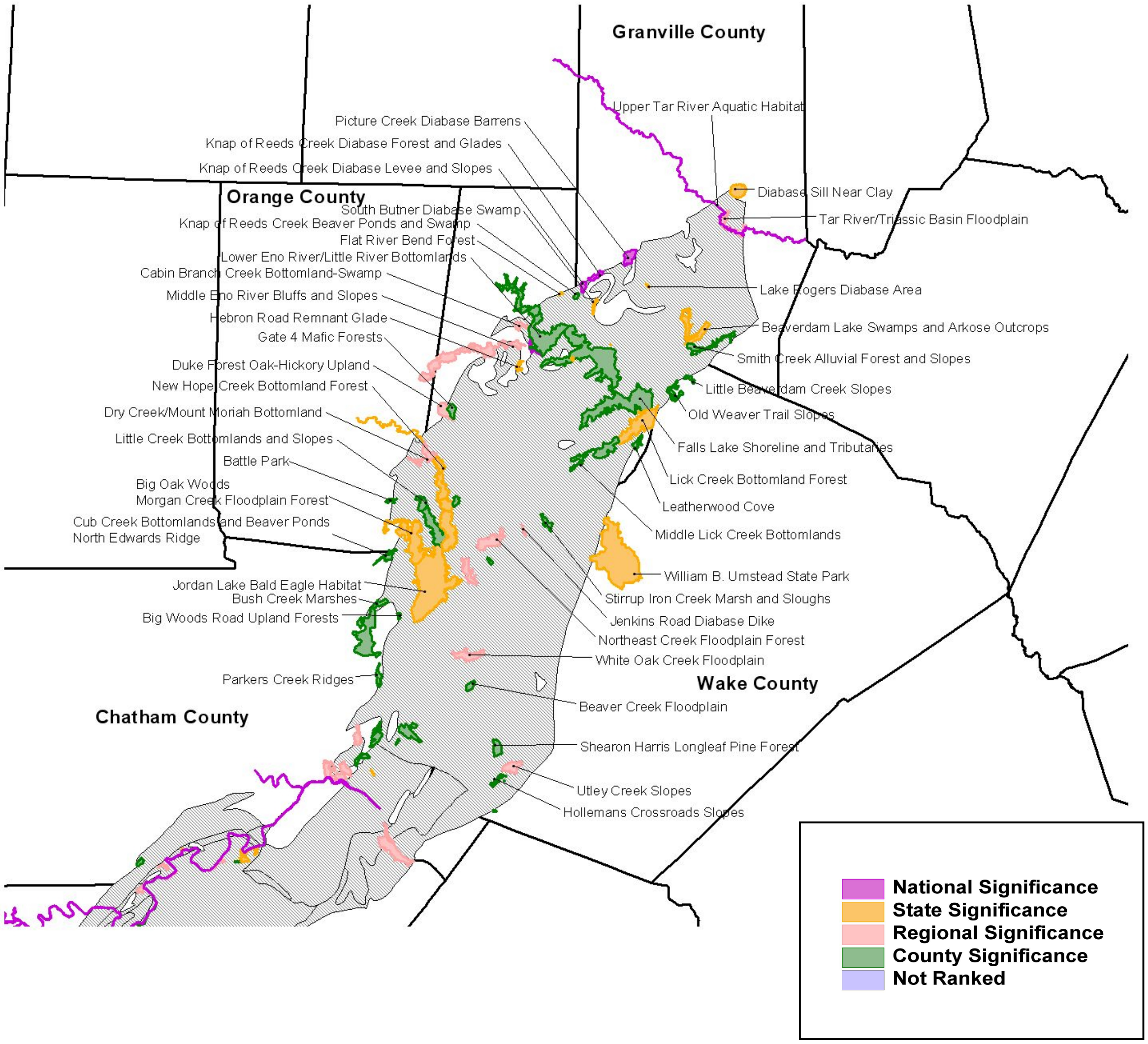


Figure 4-7. SNHAs in the Southern Portion of the Deep River Basin

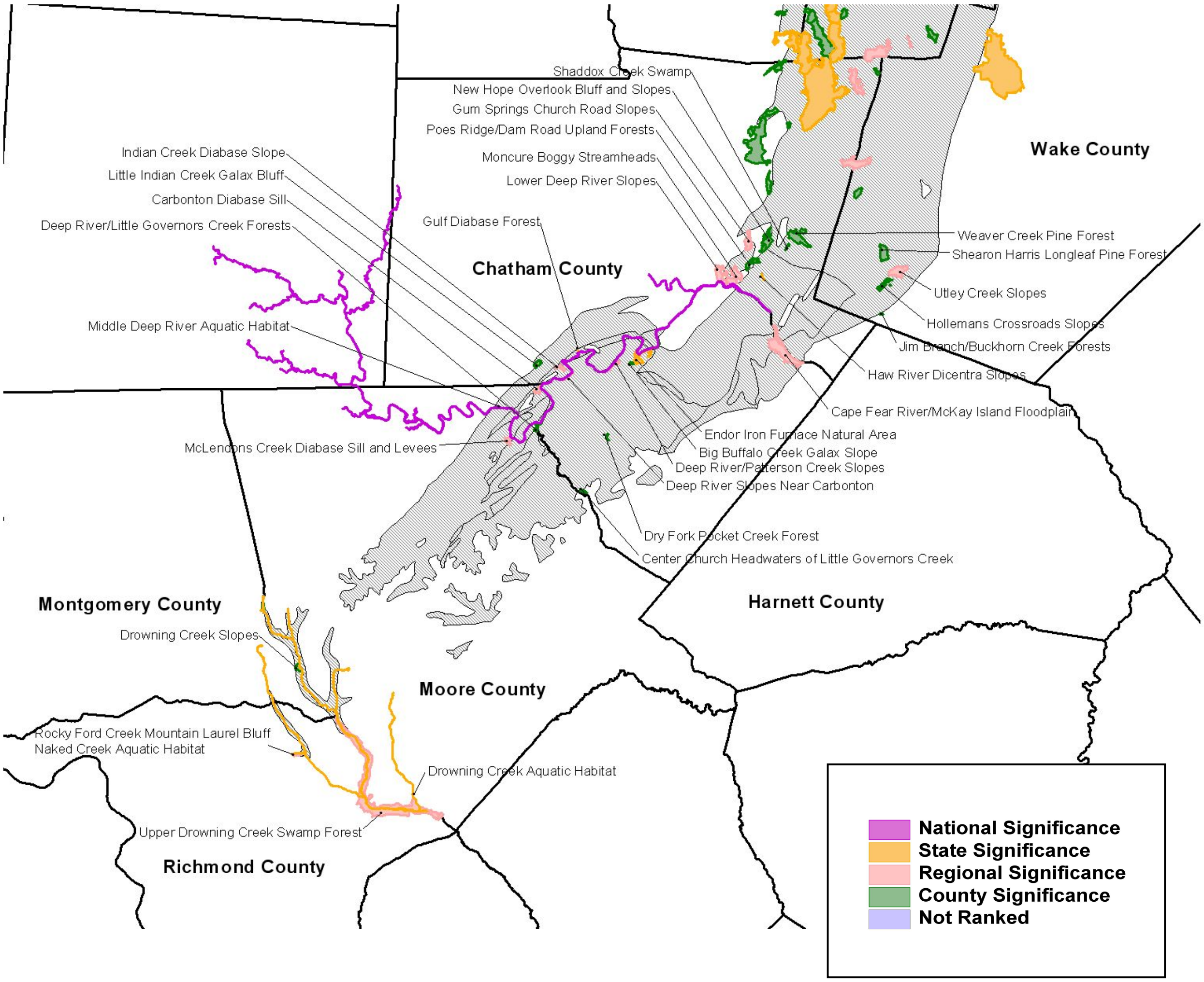


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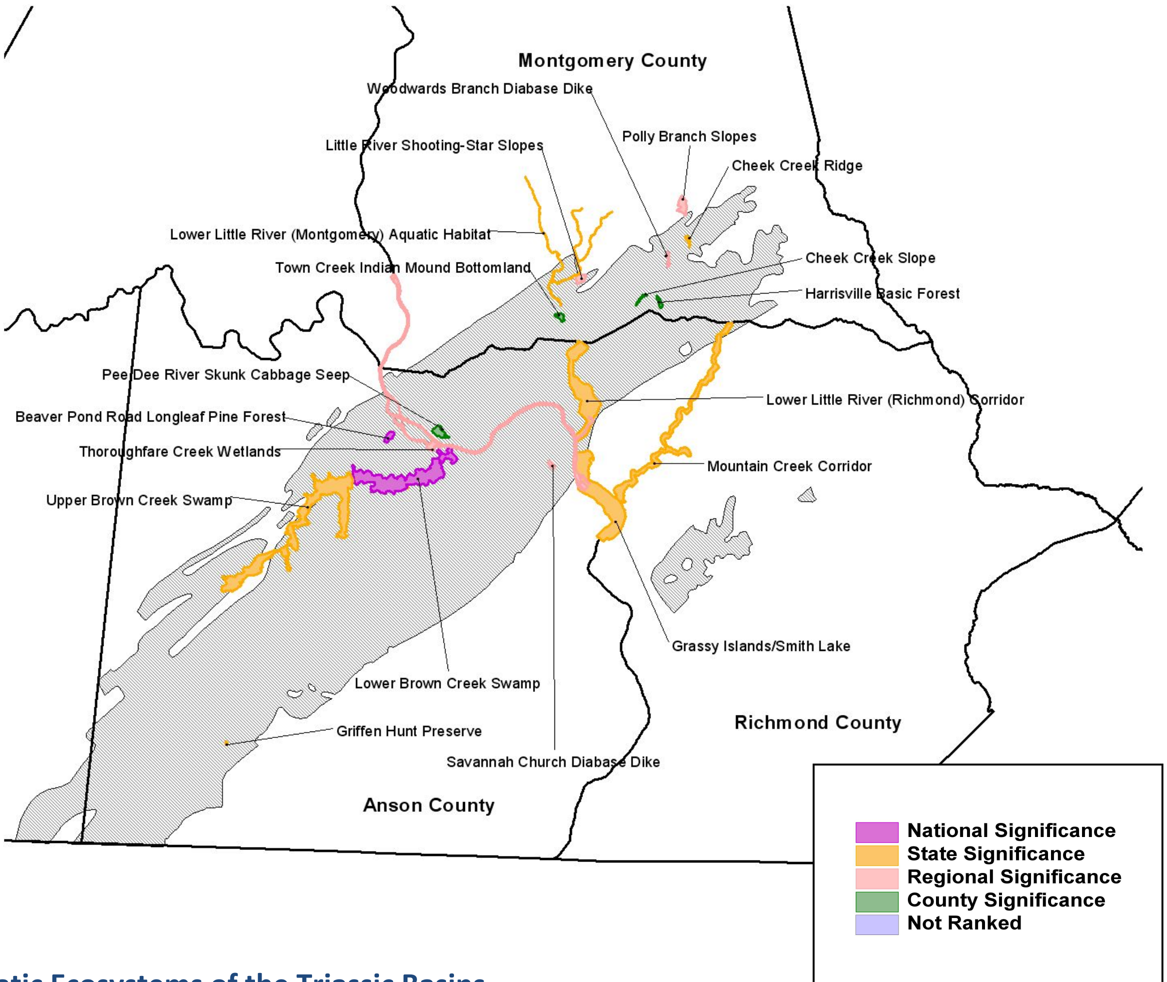
Figure 4-8. SNHAs in the Wadesboro Sub-basin



Aquatic Ecosystems of the Triassic Basins

Aquatic ecosystems perform many important functions, including recycling nutrients, purifying water, reducing flood damage, recharging groundwater and providing wildlife habitats.[195] In addition, streams, rivers and riparian ecosystems in central North Carolina, including the area underlain by the Triassic Basins, support many rare aquatic species. Native aquatic species are able to survive and reproduce within a certain range of environmental variation of the habitat, such as flow depth and velocity, water temperature, and oxygen content.[196] Because of this, aquatic species are important indicators of a stream's health.

Freshwater mussels are a particularly important group of aquatic species. These mollusks filter sediment and pollutants, making them one of the few animals that improve water quality. Mussels serve as a food source for many species of fish, reptiles, birds and mammals and provide habitat for others. A mussel's shell can be covered by aquatic insects, algae and plants,

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[195] Ibid, p. 47.
[196] NYSDEC, p. 6-3 - 6-4.

and the empty shell of a dead mussel can serve as a nesting site for small fish.[197] The United States has a greater variety of freshwater mussels than anywhere else in the world. North Carolina has about 60 mussel species; 80 percent of those species are considered rare and in need of protection.[198] Freshwater mussels face threats from non-point source pollution, sedimentation, habitat loss through channelization, clearing of riparian vegetation, dredging and dam construction.[199]

The aquatic habitats of the Deep River Basin and the Dan River Basin are well known as ecologically important systems.[200] The Deep River, being an Atlantic Slope river (meaning that it eventually drains to the Atlantic Ocean, after joining the Haw River to form the Cape Fear River), is relatively isolated from other Atlantic Slope riverine systems. Many aquatic species have no means of moving between river basins except in the rare event when geologic forces result in a change in drainage pattern. The Dan River and its tributaries support a high diversity of aquatic organisms, including largemouth bass *(Micropterus salmoides)*, sunfishes, catfishes, minnows, darters and mussels and other invertebrates. The Dan River aquatic habitat is considered by the Natural Heritage Program to be a state significant natural heritage area, and the NCWRC has identified this river as one of six high priority areas for long-term conservation. In addition, this basin is presently the focus of efforts by North Carolina and Virginia state agencies and federal agencies to restore diadromous fishery resources such as blueback herring (*Alosa aestivalis*), alewife (*Alosa pseudoharengus*), American shad (*Alosa sapidissima*), American eel (*Anguilla rostrata*), and striped bass (*Morone saxatilis*), with an initial focus on American shad. There are records for the existence of the federal and state endangered James River spiny mussel (*Pleurobema collina*), the federal species of concern and state endangered green floater (*Lasmigona subviridis*), state species of special concern riverweed darter (*Etheostoma podostemone*), bigeye jumprock (*Scartomyzon ariommus*), and notched rainbow (*Villosa constricta*), and the state significantly rare Roanoke hogsucker (*Hypentelium roanokense*) in the Dan River system. Portions of the Dan River have been formally designated a State Water Trail by the N.C. Division of Parks and Recreation; and the remaining river segments are an informal water trail.

A number of endemic species are found in the study area. The federally endangered Cape Fear shiner is one well-known, significant example. This minnow is found nowhere else on earth but in aquatic habitats in the vicinity of the fall line in Chatham, Lee, Harnett, Moore and Randolph counties. The Deep River also contains habitat for several rare freshwater mussels, including Atlantic pigtoe (*Fusconaia masoni*), Yellow lampmussel (*Lampsilis cariosa*), Savannah Lilliput (*Toxolasma pullus*), Triangle floater (*Alasmidonta undulata*), Roanoke slabshell (*Elliptio*

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[197] Virginia Department of Game and Inland Fisheries. “Freshwater Mussels.” Retrieved February 6, 2012 from http://www.dgif.virginia.gov/wildlife/freshwater-mussels.asp.

[198] Chatham Conservation Partnership. A Comprehensive Conservation Plan for Chatham County.

[199] U.S. Fish & Wildlife Service. “Discover Freshwater Mussels: America’s Hidden Treasure.” Retrieved February 24, 2012 from http://www.fws.gov/news/mussels.html.

[200] Schwab, Edward C. *A Preliminary Inventory of the Natural Areas of Lee County, North Carolina.* Compiled and edited by Laura Cotterman. NC Natural Heritage Program, NC Department of Environment and Natural Resources. Raleigh, NC, 1996.

roanokensis), Creeper (*Strophitus undulatas*), Notched rainbow (*Villosa constricta*), and Eastern creekshell (*Villosa delumbis*); fish such as the Carolina redhorse (*Moxostoma sp. 'Carolina'*) and Roanoke bass (*Ambloplites cavifrons*); the federally endangered plant Harperella (*Ptilimnium nodosum*); and the Septima's clubtail dragonfly (*Gomphus septima*).

Terrestrial ecosystems of the Triassic Basins

Some terrestrial species in the Triassic Basins depend on unfragmented upland and bottomland hardwood forests; others require early successional habitats; floodplain forests; riverine aquatic communities; or wetland habitats. Many terrestrial species depend on a combination of these habitats. Area-sensitive species require large, unfragmented habitats as home ranges and to support biological dispersal. Large, unfragmented hardwood forests with intact understories provide forage (such as acorns and nuts) and nesting sites.[201]

Many species use floodplain forests as travel corridors, and fragmentation of these areas can impact these species by altering dispersal and migration patterns. Reptiles and amphibians are especially vulnerable to these impacts. In addition, floodplain forests contain floodplain pools, that serve as breeding sites for amphibians.[202]

Natural Communities

The Triassic Basins also have high quality natural communities. Natural communities are distinct and reoccurring assemblages of populations of plants, animals, bacteria and fungi that are naturally associated with each other and the physical environment. These natural communities play an important role in maintaining natural diversity. By protecting examples of all natural community types, the majority of species can be protected without laborious individual attention. Natural communities also have intrinsic natural and aesthetic values, and may contain valuable scientific resources.[203]

The types of natural communities found in the Triassic Basin are shown in Table 4-10 below. Natural communities located in the Deep River basin include high quality examples of floodplain pools, Piedmont/low mountain alluvial forest, basic mesic forest and Piedmont longleaf pine forest. Care in siting drilling pads and infrastructure can limit direct impacts to high quality natural communities and rare plants. However, care must be taken to avoid the indirect effects of air pollution, water pollution and other impacts that can travel.

[201] Chatham Conservation Partnership. *A Comprehensive Conservation Plan for Chatham County*.
[202] Chatham Conservation Partnership.
[203] Schwab, Edward C. 1996. A Preliminary Inventory of the Natural Areas of Lee County, North Carolina. Compiled and edited by Laura Cotterman. NC Natural Heritage Program, NC Department of Environment and Natural Resources, Raleigh, NC.

Table 4-10. Natural Communities within the Triassic Basin

Natural Community
Diabase glade
Piedmont calcareous cliff
Xeric Hardpan Forest (Northern Prairie Barren Subtype)
Piedmont longleaf pine forest
Piedmont mafic cliff
Hillside seepage bog
Piedmont/mountain swamp forest
Dry Basic Oak--Hickory Forest
Xeric Hardpan Forest (Basic Hardpan Subtype)
Granitic flatrock
Upland depression swamp forest
Floodplain pool
Dry-Mesic Basic Oak--Hickory Forest (Piedmont Subtype)
Xeric hardpan forest
Basic Oak--Hickory Forest
Piedmont Alluvial Forest
Streamhead pocosin
Low elevation seep
Piedmont/coastal plain heath bluff
Coastal plain small stream swamp (blackwater subtype)
Dry oak--hickory forest
Dry-mesic oak--hickory forest
Oxbow lake
Piedmont/low mountain alluvial forest
Piedmont/mountain bottomland forest
Piedmont/mountain levee forest
Piedmont/mountain semipermanent impoundment
Basic mesic forest (piedmont subtype)
Mesic mixed hardwood forest (piedmont subtype)
Piedmont Boggy Streamhead

Rare species of the Triassic Basins

As part of its mission to preserve the biological diversity of North Carolina, the North Carolina Natural Heritage Program documents the status and distribution of the rarest plants and animals by working closely with experts from across the state and in cooperation with the U.S. Fish and Wildlife Service, the Plant Conservation Program of the N.C. Department of Agriculture and Consumer Services and the Wildlife Diversity Program of the N.C. Wildlife Resources

Commission. The Natural Heritage Program takes the lead role in North Carolina in the inventory of the state's natural diversity and the identification of important natural areas and rare species habitats.

Threatened and endangered species of the Triassic Basins

Like any other development activity, the clearing, grading and road building associated with natural gas and oil extraction and production can harm threatened and endangered species by physically altering the species' habitat. Some species, such as turtles or mussels, may be unable to avoid direct impacts due to a lack of mobility. Land-disturbance activities can also result in the loss of nesting and spawning areas, or the loss of eggs or young animals. This can result in a loss of future productivity. Species may also be impacted by exposure to spills of fluids or wastewater from the drilling or hydraulic fracturing processes. Increased vehicle traffic can also impact threatened and endangered species through direct mortality.

The North Carolina Natural Heritage Program maintains lists of species native to North Carolina that are officially recognized by federal or state agencies as protected or otherwise rare in North Carolina. These species are shown in Table 4-11 and Table 4-12 and are described in greater detail on the following pages.

Table 4-11. Federally or State-Listed Endangered or Threatened Plant Species

Taxa Group	Federal Status	State Status
Vascular Plant		
American Bluehearts, *Buchnera americana*		E
Big Shellbark Hickory, *Carya laciniosa*		T
Buffalo Clover, *Trifolium reflexum*		T
Carolina Thistle, *Cirsium carolinianum*		E
Chapman's Redtop, *Tridens chapmanii*		T
Douglass's Bittercress, *Cardamine douglassii*		T
Eaton's Ladies'-tresses, *Spiranthes eatonii*		E
Georgia Indigo-bush, *Amorpha georgiana*		E
Glade Bluecurls, *Trichostema brachiatum*		E
Harperella, *Ptilimnium nodosum*	E	E
Hoary Puccoon, *Lithospermum canescens*		T
Indian Physic, *Gillenia stipulata*		T
Jacob's Ladder, *Polemonium reptans var. reptans*		T
Low Wild-petunia, *Ruellia humilis*		E
Michaux's Sumac, *Rhus michauxii*	E	E
Narrow-leaf Aster, *Symphyotrichum laeve var. concinnum*		T
Pink Thoroughwort, *Fleischmannia incarnata*		T
Pondberry, *Lindera melissifolia*	E	E
Prairie Blue Wild Indigo, *Baptisia australis var. aberrans*		E
Rough-leaf Loosestrife, *Lysimachia asperulifolia*	E	E
Schweinitz's Sunflower, *Helianthus schweinitzii*	E	E
Serpentine Aster, *Symphyotrichum depauperatum*		E
Shale-barren Skullcap, *Scutellaria leonardii*		E
Shooting-star, *Primula meadia*		T
Smooth Coneflower, *Echinacea laevigata*	E	E
Southern Anemone, *Anemone berlandieri*		E
Southern Skullcap, *Scutellaria australis*		E
Tall Larkspur, *Delphinium exaltatum*		E
Thick-pod White Wild Indigo, *Baptisia alba*		T
Veined Skullcap, *Scutellaria nervosa*		E
Virginia Spiderwort, *Tradescantia virginiana*		T
Wiry Panic Grass, *Panicum flexile*		T

Table 4-12. Federally or State-Listed Endangered or Threatened Animal Species

Taxa Group	**Federal Status**	**State Status**
Invertebrate Animal		
Atlantic Pigtoe*, Fusconaia masoni*		**E**
Brook Floater, *Alasmidonta varicosa*		**E**
Carolina Creekshell*, Villosa vaughaniana*		**E**
Creeper **,** *Strophitus undulatus*		**T**
Dwarf Wedgemussel, *Alasmidonta heterodon*	**E**	**E**
Eastern Lampmussel*, Lampsilis radiata*		**T**
Eastern Pondmussel*, Ligumia nasuta*		**T**
Green Floater, *Lasmigona subviridis*		**E**
James Spinymussel, *Pleurobema collina*	**E**	**E**
Roanoke Slabshell **,** *Elliptio roanokensis*		**T**
Savannah Lilliput , *Toxolasma pullus*		**E**
Triangle Floater**,** *Alasmidonta undulata*		**T**
Yellow Lampmussel *, Lampsilis cariosa*		**E**
Yellow Lance*, Elliptio lanceolata*		**E**
Vertebrate Animal		
Bald Eagle*, Haliaeetus leucocephalus*		**T**
Bigeye Jumprock*, Moxostoma ariommum*		**T**
Cape Fear Shiner*, Notropis mekistocholas*	**E**	**E**
Carolina Madtom, *Noturus furiosus*		**T**
Carolina Redhorse*, Moxostoma sp. 3*		**T**
Red-cockaded Woodpecker, *Picoides borealis*	**E**	**E**
Roanoke Logperch, *Percina rex*	**E**	**E**

Federal Status

Federal status as endangered or threatened is designated by the U.S. Fish and Wildlife Service. Federally listed endangered and threatened species are protected under the provisions of the Endangered Species Act of 1973 (ESA), as amended. The ESA defines an endangered species as "in danger of extinction throughout all or a significant portion of its range." A threatened species is "likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range."[204] The area underlain by the Triassic Basin includes terrestrial and aquatic habitat for 11 species listed as endangered federally, and no species that are listed as threatened federally. These species, and the habitats needed to support them, are described in greater detail below the table.

[204] North Carolina Natural Heritage Program. *Guide to Federally Listed Endangered and Threatened Species of North Carolina.* 2001. Web. February 13, 2012. http://www.ncnhp.org/Images/Federal%20E&T%20NC-5.pdf.

Cape Fear shiner (*Notropis mekistocholas*) – The Cape Fear shiner is a small minnow that is endemic to the upper Cape Fear River Basin. It is known from tributaries and mainstreams of the Deep, Haw and Rocky rivers in Chatham, Harnett, Lee, Moore and Randolph counties. Only five populations of the shiner are thought to exist. It prefers gravel, cobble and boulder substrates, and has been seen in slow pools, riffles and slow runs. Dams and loss of riverine habitat to water impoundments, as well as deteriorating water quality, have had serious impacts on the shiner by inundating its rocky riverine habitat. Changes in stream flow, increased stormwater runoff, road construction, wastewater discharge and other forms of development have threatened the species.[205]

Dwarf Wedgemussel (*Alasmidonta heterodon*) and James Spinymussel (*Pleurobema collina*) – All river mussels live partly buried in the substratum, where they filter feed on planktonic algae, bacteria, protozoa, rotifers, fine particles of decaying leaves and other suspended organic matter. Due to their limited mobility and filter-feeding habits, river mussels are generally sensitive to stream channel erosion and siltation, high turbidity (other than food particles), severe droughts, excessive heat, low dissolved oxygen, ammonia, metals, herbicides, pesticides, blooms of blue-green algae or other algae that may be toxic, and urban development impacts.[206]

A century ago the dwarf wedgemussel lived in 15 watersheds along the Atlantic Coast from New Brunswick, Canada to North Carolina. Today this mussel is extirpated from Canada and is found in only nine watersheds in the United States.[207] It is found in portions of the Durham Sub-basin of the Deep River Basin. It inhabits creeks and rivers with a slow to moderate current and a sand, gravel or muddy bottom. The species is threatened by "Toxic effects from industrial, domestic and agricultural pollution."[208]

The James spinymussel has declined rapidly during the past two decades. It prefers free-flowing streams with a variety of flow regimes. Threats to the species include "impoundment of waterways, water pollution, stream channelization, sewage discharge, agricultural runoff including pesticides and fertilizers, poor logging and road/bridge construction practices, and discharge of chlorine."[209]

Harperella (*Ptilimnium nodosum*) – This annual herb has small, white flowers that grow in heads, similar to Queen Anne's lace. Harperella is known from 12 populations, two of which occur in North Carolina (one in Granville and one in Chatham counties). Harperella grows in

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[205] U.S. Fish & Wildlife Service. "Cape Fear Shiner (Notropis mekistocholas)." *North Carolina Ecological Services*. Web. Accessed February 13, 2012. http://www.fws.gov/nc-es/fish/cfshiner.html

[206] Chatham County Conservation Plan Appendix A., p. 8.

[207] Fisheries and Oceans Canada. "Aquatic Species at Risk – Dwarf Wedgemussel." Retrieved March 12, 2012 from http://www.dfo-mpo.gc.ca/species-especes/species-especes/dwarf_wedgemussel-alasmidonte-eng.htm.

[208] U.S. Fish & Wildlife Service. "Dwarf Wedge Mussel in North Carolina." Retrieved February 13, 2012. http://www.fws.gov/nc-es/mussel/dwmussel.html.

[209] U.S. Fish & Wildlife Service Virginia Field Office. "James Spinymussel." Retrieved February 13, 2012. http://www.fws.gov/northeast/virginiafield/pdf/endspecies/fact_sheets/james%20spiny.pdf

rocky or gravel shoals and the margins of clear, swift-flowing streams as well as on the edges of intermittent pineland ponds in the coastal plain.[210]

Michaux's sumac (*Rhus michauxii*) – Michaux's sumac is dense shrub that grows from one to three feet tall. The plant grows in sandy or rocky open woods and survives best in open areas, such as highway rights-of-way, roadsides or the edges of clearings. However, it has a low reproductive capacity, and it is threatened by habitat destruction due to residential and industrial development. Two historic populations were destroyed by development.[211]

Pondberry (*Lindera melissifolia*) – The pondberry, or Southern spicebush, is a deciduous shrub that grows up to six feet tall. It bears pale yellow flowers in the spring and red, oval fruits in the fall. It grows in seasonally flooded wetlands such as floodplains, bottomland hardwood forests or forested swales and along the margins of ponds and depressions in pinelands.[212] The pondberry is threatened by drainage ditching and land development.[213]

Red-cockaded woodpecker (*Picoides borealis*) – Red-cockaded woodpeckers are a territorial, nonmigratory species native to the American southeast. They require large areas of mature pine-dominated forest with a relatively open understory.[214] Red-cockaded woodpeckers seek out living pines with red heart disease in which to excavate nesting holes. The specificity of the bird's breeding habitat makes it extremely vulnerable to habitat loss. Today, most pine trees are cut before they reach an age at which red heart disease is common.[215]

Roanoke logperch (*Percina rex*) – This small fish presently occurs in five populations. The Roanoke logperch typically inhabits medium to large, warm, clear streams and small rivers. In North Carolina it is found in the Dan River Sub-basin of the Deep River Triassic Basin. The logperch suffered massive habitat loss following the construction of water impoundments in the Roanoke River Basin in the 1950s and 1960s, which disrupted the species' ability to move throughout its historic range. Current threats to the logperch are stormwater runoff and "spills and accidents associated with chemical releases and destruction and degradation of habitat."[216] Water withdrawals in the Roanoke River basin also threaten this species.[217]

Rough-leaf loosestrife (*Lysimachia asperulifolia*) – Rough-leaf loosestrife is a perennial herb with yellow flowers that blooms from mid-May to June. It is endemic to the coastal plain and

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[210] U.S. Fish & Wildlife Service. "Harperella in North Carolina." *North Carolina Ecological Services*. Retrieved February 13, 2012. http://www.fws.gov/nc-es/plant/harperella.html
[211] U.S. Fish & Wildlife Service. "Michaux's Sumac in North Carolina." *North Carolina Ecological Services*. Retrieved February 13, 2012. http://www.fws.gov/nc-es/plant/michsumac.html
[212] NatureServe Explorer. "*Lindera melissifolia*." Retrieved March 12, 2012 from http://www.natureserve.org/explorer/servlet/NatureServe?searchName=Lindera+melissifolia.
[213] U.S. Fish & Wildlife Service. "Pondberry (Southern Spicebush) in North Carolina." *North Carolina Ecological Services*. Retrieved February 13, 2012. http://www.fws.gov/nc-es/plant/pondberry.html
[214] Chatham County Conservation Plan Appendix A, p. 3.
[215] The Nature Conservancy. "Red-cockaded Woodpecker." *Animal Species Profiles*. Retrieved February 13, 2012. http://www.nature.org/newsfeatures/specialfeatures/animals/birds/red-cockaded-woodpecker.xml
[216] U.S. Fish & Wildlife Service Virginia Field Office. "Roanoke logperch." Retrieved February 13, 2012. http://www.fws.gov/northeast/virginiafield/pdf/endspecies/fact_sheets/roanoke%20logperch.pdf
[217] Ibid.

sandhills of North Carolina and South Carolina, and occurs on the edges between longleaf pine uplands and pond pine pocosins. Fire suppression, wetland drainage and residential and commercial development pose significant threats to the continued existence of this species.[218]

Schweinitz's sunflower (*Helianthus schweinitzii*) – This perennial herb with yellow flowers is believed to have once occupied prairie-like habitats that were maintained by fire. Today this sunflower lives on roadsides, power line clearings, pastures, woodland openings and other sunny or semi-sunny areas. Schweinitz's sunflower is threatened by fire suppression, highway construction, residential and commercial development, and maintenance activities in roadsides and utility corridors.[219]

Smooth coneflower (*Echinacea laevigata*) – The smooth coneflower is a perennial herb in the Aster family with light pink or purple drooping flowers. It is typically found in sunny places such as open woods, cedar barrens, roadsides, dry limestone bluffs and utility corridors. Historically the smooth coneflower existed in Pennsylvania, Maryland, Virginia, North Carolina, South Carolina, Georgia, Alabama and Arkansas, but today is found only in Virginia, North Carolina, South Carolina and Georgia. In North Carolina, it is found in Durham, Granville, Mecklenburg and Rockingham counties. It is threatened by fire suppression and habitat destruction resulting from highway construction, residential and commercial development, and maintenance activities in roadsides and utility corridors.[220]

State status and state regulations related to endangered, threatened and special concern species

Plants and animals have different state status definitions and are assigned status by different agencies. The Plant Conservation Program (part of the N.C. Department of Agriculture and Consumer Services) determines plant statuses. The North Carolina Wildlife Resources Commission and the Natural Heritage Program determine animal statuses.

State listed plants

Endangered, threatened and special concern species of plants have limited protection status under the Plant Protection and Conservation Act of 1979 (G.S. 106, Article 19A). The Plant Protection and Conservation Act and the North Carolina Endangered Species Act (G.S. 113, Article 25) prohibit the takings of state-listed species. In addition, these acts state that they do not limit the rights of a landowner in the lawful management of his or her land. In the area underlain by the Triassic Basin, 53 species are listed by the state as endangered or threatened in North Carolina. Of these, 32 are plants.

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[218] U.S. Fish & Wildlife Service. "Rough-leaf Loosestrife (Lysimachia asperulifolia)." *North Carolina Ecological Services*. Retrieved February 14, 2012. http://www.fws.gov/nc-es/plant/rllooses.html

[219] U.S. Fish & Wildlife Service. "Schweinitz's sunflower (Helianthus schweinitzii)." *North Carolina Ecological Services*. Retrieved February 14, 2012. http://www.fws.gov/nc-es/plant/schwsun.html

[220] U.S. Fish & Wildlife Service. "Smooth Coneflower (Echinacea laevigata)." *North Carolina Ecological Services*. Retrieved February 14, 2012. http://www.fws.gov/nc-es/plant/smooconefl.html

State-listed animals

Endangered, threatened and special concern species of mammals, birds, reptiles, amphibians, freshwater fishes, crustaceans and freshwater and terrestrial mollusks have limited legal protection status in North Carolina under the North Carolina Endangered Species Act (G.S. 113, Article 25). Of the 53 species listed by the state as endangered or threatened in North Carolina, 21 are animals.

Potential impacts to fish, wildlife and important natural areas based on studies from other states

At this time, there is insufficient information to predict specific impacts of natural gas drilling and production to fish, wildlife and important natural areas in North Carolina. However, research on impacts that have occurred is summarized below. The potential impacts of natural gas exploration and production to fish, wildlife and important natural areas are organized within this section into three major types of impacts: land use changes, water availability and exposure to spills, releases and air emissions.

Natural gas drilling operations on public lands

Lands that are owned by the government, such as state parks and game lands, are not necessarily excluded from natural gas drilling. In 2011, Ohio Gov. John Kasich and the State Legislature opened up state parks for oil and gas drilling. The state "will earn at least 30 percent of royalties from land leases," and the proceeds are earmarked for improvements on the state's lands.[221]

Drilling has taken place in Pennsylvania state forests since 1947, and the state benefits from royalties and bonus payments associated with that drilling. Until 2009, "oil and gas revenue had been reserved for conservation, flood control and recreation purposes."[222] In 2009, Pennsylvania's government "took more than $399 million from the fund to help balance the next two budgets." More than 700,000 acres of Pennsylvania state forests have been leased.[223] Drilling also occurs on state game lands in Pennsylvania. Although the State Game Commission "owns 1.4 million acres of game lands, it does not always own the mineral rights beneath them, so private owners can lease them out to gas companies."[224]

Federal lands are also used for natural gas exploration and production. The Bureau of Land Management (BLM) issues leases for natural gas development on lands managed by the BLM and other federal agencies, such as the U.S. Forest Service. The BLM is currently considering

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[221] Guillen, Joe. "Drilling in state parks for oil and gas: Whatever happened to?" *The Plain Dealer.* January 14, 2012. Retrieved February 26, 2012 from http://blog.cleveland.com/metro/2012/01/drilling_in_state_parks_for_oi.html.
[222] Detrow, Scott. "Can Pennsylvania's State Forests Survive Additional Marcellus Shale Drilling?" StateImpact. September 12, 2011. Retrieved February 26, 2012 from http://stateimpact.npr.org/pennsylvania/2011/09/12/can-pennsylvanias-state-forests-survive-additional-marcellus-shale-drilling/.
[223] Ibid.
[224] Seelye, Katharine Q. "Gas Drillers Invade Hunters' Pennsylvania Paradise." *The New York Times*. November 11, 2011. Retrieved February 26, 2012 from http://www.nytimes.com/2011/11/12/us/pennsylvania-hunting-and-fracking-vie-for-state-lands.html?pagewanted=all.

regulations that would require disclosure of information about chemicals used in hydraulic fracturing on federal lands.[225]

Impacts due to land disturbance

The exploration and production of natural gas can disturb a large amount of land as oil and gas operators develop gravel access roads, well pads and utility corridors. In the process of natural gas extraction and production, land is graded and cleared to develop well pads, access roads and utility corridors for water and electrical lines, gas gathering lines, and compressor facilities.

The New York Draft Environmental Impact Statement includes industry estimates of the average size of a multi-well pad. During drilling and hydraulic fracturing, the average well pad is estimated to be 3.5 acres. Once production begins at the well pad, a portion of the area used during the drilling and fracturing phase is partially reclaimed (as required by law in New York), and the remaining well pad size is estimated to be 1.5 acres on average.

The NYSDEC also contains industry estimates for the total land disturbed for well pads, including land disturbed for access roads and utility corridors. According to the industry estimates in the NYSDEC, during drilling and hydraulic fracturing, the average total land disturbance is 7.4 acres per well pad. The total acreage that remains disturbed during the production phase is 5.5 acres on average per well pad.

If natural gas drilling becomes common in the Triassic Basins, North Carolina could potentially experience additional land disturbance for the development of utility corridors for transmission lines than experienced elsewhere. There are fewer transmission lines in this state than in others that are already experiencing oil and gas extraction activities.

The estimates in the NYSDEC's Draft Generic Environmental Impact Statement do not include land disturbance for surface water impoundments, which have surface acreage of up to five acres. Each surface water impoundment can serve multiple well pads. At least one other estimate does include this land disturbance, and reports a higher amount of total land disturbance than the NYSDEC. The Nature Conservancy conducted a study in 2010 on the effects of horizontal hydraulic fracturing in Pennsylvania on high priority conservation areas. The study included an assessment of aerial photography of 242 Pennsylvania natural gas well locations, using data from the Pennsylvania Department of Environmental Protection, both before and after development. The study reported that nearly nine acres of land was disturbed per well pad (3.1 acres on average for the well pad and an additional 5.7 acres for roads, water impoundments and utility corridors for pipelines).[226]

Land disturbance associated with natural gas drilling, extraction and production activities could have a significant adverse impact on habitats and on the species that live both in the area that is disturbed and in neighboring areas, such as those described below.

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[225] Fugleberg, Jeremy. "First-ever federal fracking rules draw mixed Wyoming reviews." *Casper Star-Tribune*. February 16, 2012. Retrieved February 26, 2012 from http://trib.com/news/state-and-regional/first-ever-federal-fracking-rules-draw-mixed-wyoming-reviews/article_d0c16030-a105-51bf-8727-7c7aea09f031.html.

[226] NYSDEC, p. 6-76.

Habitat fragmentation and habitat loss

Land disturbance can cause habitat fragmentation and habitat loss. Habitat fragmentation is the alteration of habitat that results in changes in area, configuration or spatial patterns from a previous state of greater continuity. Habitat loss is the conversion of areas of habitat to uses not compatible with the needs of wildlife. Habitat degradation is the diminishment of habitat value or functionality. Habitat fragmentation and habitat loss can lead to reduction in the total area of habitat, the isolation of one habitat unit from other units of habitat, and the separation of populations.

Habitat fragmentation and loss can occur naturally through events such as forest fires and volcanoes, but it can also be caused by the construction of well pads, access roads, pipelines and other infrastructure necessary for natural gas exploration and production.

Habitat connectivity is important; many wildlife species need to be able to move among various habitats to survive. For instance, many amphibians breed in wetlands but spend most of their lives in uplands away from wetlands. Therefore amphibians have different habitat requirements at different times of the year. Alterations to either of these habitats or barriers that would prevent them from moving between the two habitats will impact amphibians and other species that depend on habitat connectivity.

In addition to habitat loss and degradation, natural gas drilling can impact wildlife through increased mortality, increasing edge habitats and increased traffic, noise, lighting and air emissions.[227]

Forests provide ecological, economic and social benefits such as water quality protection, air quality enhancement, flood protection, pollination, pest predation, wildlife habitat and diversity, and opportunities for recreation. Large, continuous forest patches are particularly valuable. Forest cover helps maintain water quality, and forests and forestry practices are vital to the long-term sustainability of clean and affordable drinking water.

Although forestland is common throughout the Triassic Basin, current land development practices have already resulted and will continue to result in losses of large, contiguous forested areas. As forests are fragmented, the populations of species that depend on interior forests decline. Protecting remaining patches of forests is therefore critical.

Forests may be fragmented as a part of the land disturbance for natural gas drilling operations. Lands adjacent to well pads can be affected by natural gas extraction, even if they are not directly cleared, through the fragmentation of habitats and changing conditions for sensitive species that depend on interior forest conditions. Interior forest species may avoid edges because of the increased risk of predation or because of changes in canopy cover, humidity and light. Some species are attracted to forest edges. Some species, such as invasive plants, thrive on forest edges, displacing native species. Land disturbance increases these edge habitats, and this type of disturbance is referred to as the “edge effect.”

[227] NYSDEC, pp. 6-67 – 6-69.

According to the NYSDEC, "research has shown measurable impacts often extend at least 330 feet (100 meters) into forest[s] adjacent to an edge."[228] A professor of wildlife resources at Penn State, Margaret Brittingham, is beginning to study the effects of the edges created by drilling in Pennsylvania game lands on flora and fauna. Dr. Brittingham "expects that some wildlife populations, like deer, are expected to increase after the drillers leave, but that songbirds, salamanders and frogs and other amphibians that help maintain a forest's ecological balance are likely to decline."[229]

The density of wells per well pad can either aggravate or mitigate the land disturbance impacts of the natural gas operation. More wells per pad equates to less land disturbance and more limited impacts on the landscape. In The Nature Conservancy's 2010 study, the average well pad density was two wells per pad. Although gas drilling operators may eventually install more wells on each pad, two are initially drilled "as companies quickly move on to drill other leases to test productivity and to secure as many potentially productive leases as possible" before those leases expired (typically after five years if no drilling occurs).[230] If these wells are productive, gas operators will return to drill additional wells in the future.[231]

The study compared three drilling scenarios for Pennsylvania (low, medium and high) and found that the most likely drilling scenario in Pennsylvania would result in a density of one well pad per 386 acres. This could be different in North Carolina, if a regulatory structure were developed that required a certain density of well pads, as does New York State. Some of the findings from The Nature Conservancy's study were:

- A majority of projected well locations were found in forests (64 percent for each of the three development scenarios). By 2030, between 34,000 and 82,000 acres of forest cover could be cleared by new Marcellus gas development in Pennsylvania, creating new forest edges "where the risk of predation, changes in light and humidity levels, and expanded presence of invasive species could threaten forest interior species in 85,000 to 190,000 forest acres."[232] The report recommends locating energy infrastructure toward the edges of large forest patches.
- Between 300 and 750 well pads could be located within a half mile of "exceptional value" streams, the Department of Environmental Protection's highest water quality designation.
- Nearly 40 percent of Pennsylvania's globally rare and Pennsylvania threatened species can be found in areas with a high potential for Marcellus shale gas development.

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[228] NYSDEC, p. 6-75.
[229] Seelye, 2011.
[230] The Nature Conservancy. "Pennsylvania Energy Impacts Assessment Report 1: Marcellus Shale Natural Gas and Wind." p. 13.
[231] The practice of drilling two wells initially and returning to the well pad after the wells proved productive was also mentioned by staff members of the Pennsylvania DEP.
[232] The Nature Conservancy. "Pennsylvania Energy Impacts Assessment Report 1: Marcellus Shale Natural Gas and Wind." p. 6.

The report projects extensive overlaps between Marcellus development and state forests, parks and game lands.

The NYSDEC concluded that “for each acre of forest directly cleared for well pads and infrastructure in New York, an additional 2.5 acres can be expected to be indirectly impacted,”[233] because of the edge effect. This would have a high impact on interior forest bird species.

Forest matrix blocks are areas that “contain mature forests with old trees, understories, and soils that guarantee increased structural diversity and habitat important to many species.”[234] Within these forest matrix blocks are smaller ecosystems, such as wetlands and streams, which depend on the forest for their long-term health. The New York State Department of Environmental Conservation assessed the 2010 work of the New York Natural Heritage Program in identifying New York’s forest matrix blocks and predicting corresponding forest connectivity areas. NYSDEC concluded that 57 percent of the area underlain by the Marcellus shale in New York is forested, and it is likely that forests in New York would experience negative impacts similar to those predicted in Pennsylvania from high-volume hydraulic fracturing. NYSDEC reports that “In order to minimize habitat fragmentation and resulting restrictions to species movement in the area underlain by the Marcellus, it is recommended that forest matrix blocks be managed to create, maintain, and enhance the forest cover characteristics that are most beneficial to the priority species that may use them.”[235]

In North Carolina’s Triassic Basins, there are greater than 550,000 acres of forested land. Within the Dan River Basin, 56 percent of land is forested; in the Deep River Basin, 64 percent of land is forested; and in the Davie Basin, 49 percent of land is forested.

Invasive species

The extraction and production of natural gas can transport invasive species through three main pathways: increased edges due to land disturbance, vehicles and equipment, and surface water transport. Invasive plants readily colonize disturbed areas and habitat edges. Once established, invasive plants continue to spread to adjacent habitats. For example, invasive vegetation like privet can also establish itself in forests. Invasive plant species are aggressive competitors and can significantly reduce the diversity of native plant and animal species.[236]

Any activity involving land disturbance, including well pad construction, access roads and surface impoundments for fresh water storage, has the potential to introduce and transfer invasive species. Machinery and equipment may come into contact with invasive species and

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[233] NYSDEC, p. 6-81.
[234] NYSDEC, p. 6-82.
[235] NYSDEC, p. 6-83.
[236] New Hampshire Department of Transportation. *Best Management Practices for Roadside Invasive Plants.* 2008. Retrieved March 6, 2012 from http://www.fws.gov/northeast/cpwn/pdf/activities/InvasiveSpecies/BMPsforRoadsideInvasivePlantsNH.pdf.

carry them via tires, buckets or other parts of the equipment to another location on site, a separate site or a location in between.[237]

Invasive species are not limited to terrestrial habitats. The transportation of surface water across long distances to supply hydraulic fracturing operations presents the opportunity to transfer invasive aquatic plant and animal species within North Carolina. If spills or discharges occur during truck accidents or freshwater pipeline leaks, invasive species may be transferred from one watershed to another. One notable example is hydrilla (*Hydrilla verticillata*), a submersed aquatic plant native to Africa that forms nearly impenetrable mats of stems and leaves at the water's surface. Hydrilla crowds out beneficial native vegetation and causes changes in fish populations and other aquatic ecology. Hydrilla was introduced to the United States as an aquarium plant but is now "the most serious weed threat in North Carolina's inland waters."[238]

Potential impacts from spills, releases and air emissions

Spills are extremely likely to occur with any natural gas drilling and production in North Carolina. Along with violations for sedimentation and erosion control, spills were one of the two most common types of violations found by the Pennsylvania Department of Environmental Protection in gas drilling operations.[239] A number of different components of natural gas exploration and drilling may be spilled, including hydraulic fracturing fluids, drilling muds, wastewater and freshwater. The impact of spills can be compounded by insufficient stormwater controls. If spills occur before or during rain events, runoff can carry spilled fluids into surface waters.

Spills of fluids related to gas drilling operations

Hydraulic fracturing fluids may include toxic constituents, as described in Section 4.A. A spill of hydraulic fracturing fluid components or drilling mud could occur during transportation of those fluids, where they could drain to nearby streams. Spills could also occur on the well pad, if equipment malfunctions or if a storage device is overtopped. Such a spill could leave the well pad and enter a nearby stream if spill prevention at the well pad is inadequate or spill prevention systems fail.

Aquatic environments may be sensitive to the potential water contamination associated with natural gas exploration and production, such as spills of hydraulic fracturing fluids or spills of freshwater withdrawn for use in hydraulic fracturing that is of a lower quality than the water into which it is spilled.

Wastewater from hydraulic fracturing, which includes the components of the hydraulic fracturing mixture as well as naturally occurring radioactive materials (NORMS) from the shale formation, may be spilled at the well pad or during transportation of wastewater to a disposal

[237] NYSDEC, p. 6-86.
[238] North Carolina Agricultural Extension Service. "Hydrilla: A Rapidly Spreading Aquatic Weed in North Carolina." Publication Number AG-449. North Carolina State University, 1992. Retrieved March 6, 2012 from http://www.weedscience.ncsu.edu/aquaticweeds/hydrilla.PDF.
[239] Personal communication, February 3, 2012.

site. In addition, wastewater that is improperly treated may be released to surface waters, impacting aquatic ecosystems.

A recent example of such a spill occurred in April 2011 in Leroy Township, Pa., when a mechanical failure caused the operator to lose control of a wellhead during hydraulic fracturing. Ten thousand gallons of fluids from the well mixed with rainwater and Towanda Creek, a tributary of the Susquehanna River, and an unnamed tributary of Towanda Creek.[240] A berm around the exterior edge of the well pad, designed to contain stormwater and spills, failed because a truck had recently backed into it.[241]

According to a press release from the Pennsylvania Department of Environmental Protection (DEP), "Chesapeake took two days to stop the flow from the well and four days beyond that to bring the well fully under control."[242] The day after the operator lost control of the well, DEP detected "levels of total dissolved solids, chlorides and barium that were higher than background levels at the mouth of the tributary, where it enters Towanda Creek. Subsequent testing further downstream and on the following days showed these levels returned to normal background levels."[243] According to a report by a consultant hired by Chesapeake, the spill did not cause any long-term damage to Towanda Creek. Chesapeake has indicated that it is making operational improvements to ensure this type of failure does not happen again, including marking berms so that truck drivers are better able to see them. This incident is just one example of how a spill from a drilling site can enter surface waters.

If spills to surface waters do occur, there could potentially be fish kills or other threats to aquatic life. This could trigger fish consumption advisories, notices sent by the N.C. Department of Health and Human Services that notify people to limit consumption or avoid eating fish that may contain contaminants.

Spills may not just threaten aquatic animals. Some reports have indicated that spills have affected cows, dogs and wildlife. In 2009, 17 cattle in Louisiana died in a pasture near a well that was being hydraulically fractured. According to the *Shreveport Times*, "Witnesses reported hearing [the cattle] bellowing and seeing them bleeding before they fell over dead."[244] The Louisiana Department of Environmental Quality (DEQ) determined that "fluid leaked from the well pad, then ran into an adjacent pasture after a rain," and a toxicologist hired by DEQ determined the cattle deaths "were consistent with and suggestive of petroleum hydrocarbon ingestion with secondary aspiration pneumonia."[245] DEQ fined the drilling operator and a contractor for breaking three regulations in connection with the incident, including causing or

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[240] Sunday, Kevin. "DEP Fines Chesapeake Appalachia $565,000 for Multiple Violations." Pennsylvania Department of Environmental Protection. February 9, 2012. Retrieved February 26, 2012 from http://www.portal.state.pa.us/portal/server.pt/community/news_releases/14288.
[241] Personal communication with Brian Grove of Chesapeake Energy.
[242] Sunday, 2012.
[243] Ibid.
[244] Welborn, Vickie. "Chesapeake, Schlumberger fined $22,000 each in cattle deaths." *Shreveport Times*. March 26, 2010. Retrieved February 26, 2012 from http://pqasb.pqarchiver.com/shreveporttimes/access/1994311381.html?FMT=ABS&date=Mar+26%2C+2010.
[245] Ibid.

allowing a regulated solid waste to be deposited without a permit, failing to submit a written report about the unauthorized discharge to DEQ within seven days, and failing to notify the state hazardous materials hotline.[246] The drilling operator and the contractor each paid $22,000 in fines and the drilling operator compensated the cattle owners for their losses. However, both companies denied that the material discharged from the well site killed the cattle.[247]

Contaminated freshwater

Freshwater may be spilled during transportation or because of a leaking pipeline. The release of freshwater may be detrimental to aquatic species and habitats if it enters a surface water considered to be of a higher quality than the source from which it came. For instance, a spill of water from a Class C water to a high quality stream may contaminate the high quality stream and adversely impact the aquatic species within it.

Sedimentation and erosion

In addition to exposure to contaminants due to spills, oil and gas drilling can damage surface waters through sedimentation and erosion. Land disturbance can also causes sedimentation and erosion, which can impact wetlands, streams and other aquatic habitats. Rain events can cause soil erosion in non-vegetated areas, causing sediment and any associated contaminants to impact surface waters, thereby impacting the species living in these habitats. Effective sedimentation and erosion control measures are necessary to reduce the impacts of erosion and sedimentation on aquatic species and their habitats.

At the same time Chesapeake Energy was fined for the spill in Leroy Township, Chesapeake was fined for a March 2011 incident in West Branch Township, "where sediment discharged into a stream classified as high quality," and for 2010 violation that impacted a wetland and allowed sediment to enter Sugar Creek in North Towanda Township.[248] In the first incident, an access road and well pad were constructed without sufficient erosion controls, and heavy rain caused sediment to run-off into a stream, eventually impacting a local authority's water treatment filters. In the second incident, part of the well pad was built in a wetland, and "the company filled a third of an acre of wetlands without authorization," causing temporary impacts to the wetland through erosion and sediment to enter Sugar Creek.[249]

Impacts to wildlife, livestock and pets

There is a limited amount of research on the impacts of natural gas drilling on wildlife, livestock and pets. This could be due in part to nondisclosure agreements between injured parties and corporations that prevent information from being documented. One peer-reviewed study researched the impacts of gas drilling on human and animal health. Their research is essentially a collection of case studies, and the authors acknowledge the study "is not an epidemiologic analysis of the health effects of gas drilling."[250] The authors documented cases of animal and

[246] Ibid.
[247] Ibid.
[248] Ibid.
[249] Ibid.
[250] Bamberger, Michelle and Robert E. Oswald. "Impacts of Gas Drilling on HUman and Animal Health." *New Solutions*, vol 22(1) 51-77, 2012.

owner health problems with potential links to gas drilling and interviewed animal owners living near gas drilling operations in six states. They researched 24 cases in all, involving alleged spills of wastewater, stormwater runoff from a well pad onto a neighboring property, drilling fluids spilling off a well pad during a blow out, and hydraulic fracturing fluids spilling from a holding tank, among others. According to this study, reproductive problems were "the most commonly reported symptoms."

Such spills could also have impacts on the food supply. In the Bamberger study, the authors

> "documented cases where food-producing animals exposed to chemical contaminants have not been tested before slaughter and where farms in areas testing positive for air and/or water contamination are still producing dairy and meat products for human consumption without testing of the animals or the products."[251]

In addition to exposure for spills, wastewater ponds and surface water impoundments used for natural gas drilling may become attractive to wildlife. If untreated wastewater is stored in settling ponds, wildlife species that swim in, drink from, or consume vegetation growing in the wastewater may be impacted by the chemicals and contaminants in this wastewater. If these animals are subsequently harvested by hunters, these potential wildlife health impacts may impact humans as well.

Surface water withdrawals

Aquatic biodiversity and the health of aquatic ecosystems depend on natural flow patterns. Aquatic ecosystems could be adversely impacted by changes to water quality or quantity, insufficient stream flow for aquatic life or water withdrawals. Aquatic environments will be at risk from withdrawals of water at a rate or quantity that reduces the flow so much that ecology of the water body is harmed. During hydraulic fracturing for shale gas production, approximately five million gallons of water is used per well. Impacts to aquatic habitats and species due to water withdrawals and the potential for low flow conditions are discussed in further detail in Section 3.A, Water supply.

Potential impacts to recreational fishing and hunting

The process of extracting and producing natural gas or oil can have impacts for public recreation activities such as fishing and hunting. The land disturbance, noise, visual impacts and increased truck traffic associated with natural gas production could disturb the peaceful environment associated with public recreation areas, as well as causing loss of access, altered landscapes and animal behavior changes, among other concerns. The potential impacts to recreational fishing and hunting are described in greater detail in Section 6D, *Potential impacts on recreation activities*.

[251] Bamberger and Oswald, p. 67.

I. Management and reclamation of drilling sites (including orphaned sites)

Definitions

Under North Carolina's Oil and Gas Conservation law (North Carolina General Statutes Chapter 113, Article 27), once an exploration well is completed or stops producing, notice is given to the Division of Land Resources (DLR) along with a fee paid for a permit to plug and abandon the well. DLR issues a permit and conducts a final inspection of the abandoned well. Proper abandonment of the well will result in the return of the bond carried on the well during the entire well lifecycle.

Orphaned oil and gas wells are wells that have been plugged, but not inspected by DLR; wells that have been improperly abandoned without the correct plugging; and wells that have not been plugged and have been left as an open hole.

History of oil and gas exploration in North Carolina

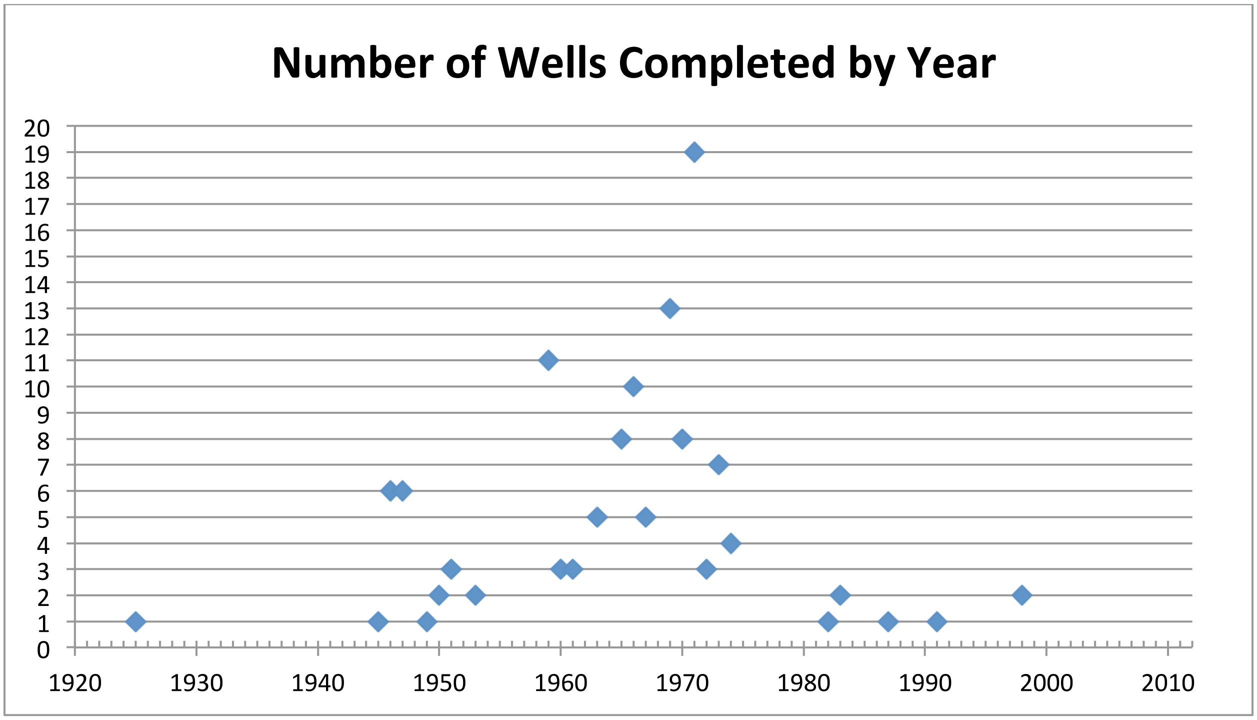
The history of oil and gas exploration in North Carolina spans more than 80 years, with the earliest oil well drilled in 1925 in Craven County (Great Lakes #2 – API No.: 32-049-1). The most recent oil and gas wells were drilled in 1998 in Lee County (Simpson #1 – LE-OT-1-98 and Butler #3 – LE-OT-2-98).

To date, 128 oil and gas exploration wells have been completed in North Carolina. Figure 4-9 shows the number of wells completed per year using data from N.C. Geological Survey Information Circular 22 – "Exploration Oil Well of North Carolina 1925 – 1976," compiled by James C. Coffey (1977). The 120 wells listed in that publication have been increased to 128 to include seven wells completed from 1976 to 1998 and the addition of another well drilled in Pamlico County in 1947 (API No.: 32-137-0004).

Oil and gas exploration wells have been drilled in 23 counties. These are listed in rank order: Onslow (22), Brunswick (16), Carteret (16), Dare (15), Hyde (10), Lee (8), Pender (8), Beaufort (5), Tyrrell (5), Pamlico (4), New Hanover (3), Camden (2), Craven (2), Currituck (2), Washington (2), Bertie (1), Bladen (1), Duplin (1), Gates (1), Hertford (1), Jones (1), Pasquotank (1) and Wilson (1).

Over the years, several exploration campaigns have concentrated on one or two adjacent counties. From 1945 to 1947, Carteret, Pamlico and Dare counties were the targets. In 1959, the focus was on Hyde and Onslow counties. By 1963, it was Beaufort; Dare and Hyde in 1965; and in 1966-67 Pender and Onslow. Exploration expanded in 1969, when13 wells were drilled in nine different counties. By the early 1970s, the focus had narrowed to Onslow and Brunswick; in 1971 it was Brunswick (11 of 19), Dare and Tyrrell; and in 1972 to 1974 Tyrrell, Carteret, Dare and Lee. Since 1974, eight wells have been drilled, all of them in Lee County.

Figure 4-9. Time series of the number of exploration oil and gas wells completed in North Carolina. The most active exploration years, those with 10 or more wells completed are: 1971 with 19; 1969 with 13; 1959 with 11 and 1966 with 10.



Oil and gas exploration well information held by the N.C. Geological Survey

Upon submission of an application for an oil and gas drilling permit, a permanent file is created for that well. The proposed well is assigned an American Petroleum Institute (API) number. This is a three-part number; the first two digits represent the state code, e.g. 32 for North Carolina. The second three-digit number is the county, e.g., 013 for Beaufort County. The third number represents the chronology of the well completion within the county, e.g., 1 for the first well in the county.

Only one well, drilled in Craven County in 1925, precedes the North Carolina Oil and Gas Conservation Act of 1945. Each well has a unique NCGS code and well name. Well files can include permit applications, issued permits, drilling reports, completion reports, well location maps, correspondence between the department and the owner, operator and/or driller, mud logs and all geophysical logs. These files are stored in locking metal filing cabinets in the Core Repository at the NCGS Raleigh Field Office on Reedy Creek Road in Raleigh. All well information is stored by county in chronological order, from first well drilled in the county to the latest.

A digital database of everything known about each oil and gas exploration well is also maintained. NCGS is currently using the ESRI ArcGIS 8.3 platform. Decidegrees of latitude and longitude are provided in the database for plotting in a GIS environment.

The explanation for the data fields is listed below. Note that the well locations are reported in degrees, minutes and seconds. One second of latitude (1/60 of one minute x 1/60 of one degree) equals 0.0003 of a degree.

0.0003 degrees x 111.195 km/degree x 62 miles/100 km x 5,280 ft/mile = 109 feet.

One-half second of latitude equals 50 feet. The well locations listed in the files are between 50 feet to 110 feet of the abandoned well location.

Oil and gas exploration well database data field explanation

Listed in the table below is the explanation of the data fields found in the oil and gas exploration well database.

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Data field explanations

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NCGS Code: alphanumeric code for the hole of interest, format is 2-letter county abbreviation, type of hole

(T=test; C=core; A=auger; P=producing (outdated water-well designation); and OT=oil & gas exploratory hole), sequence number within a given year, and year drilled.

PP 796: USGS Professional Paper 796 cross-reference number for the well.

Well Name: usually lease-name for oil & gas exploration wells

Other Code: company code, or other tracking code used to id the well.

Latitude: degrees, min, sec

Longitude: degrees, min, sec

Well datum: elevation of measuring point for logging, usually ground surface, but in the case of oiltests, is usually the KB (kelly bushing).

County: self-explanatory

Operator: owner of well

Depth: total depth of well

Drilled by: actual driller, not owner of hole

Date Drilled: full year, month, day

Logged by: geophysical logging contractor

Date logged: self-explanatory

Logs: listing of geophysical logs run on the borehole, "standard" abbreviations used, call if you need a list.

Samples: samples archived by NCGS, boolean field, true or false

Slides: paleontologic slides available, boolean field, true or false

Lith log: good quality lithologic log for the hole, boolean field, true or false

Cuttings: cuttings available, boolean field, true or false

Ctgs Interval: cuttings intervals archived

Core: core available, boolean field, true or false

Core Interval: core intervals archived

SWC: side wall cores (oiltests), boolean field, true or false

SWC Interval: side wall core intervals

Interval: continuation of side wall core intervals

Tops: formation tops picked, boolean field, true or false

Basement: bedrock reached, boolean field, true or false

BsmtLith: bedrock lithology

GW Grid: NC Ground Water Section grid coordinates for borehole (a filled field indicates a well that the Groundwater Section drilled or logged).

Ctgs Footage: total cuttings footage for hole.

Core Footage: total core footage for hole.

Bsmt depth: log depth of bedrock surface

Bsmt altitude: depth of bedrock, reference MSL

Type: type of hole, Welldata=municipal, industrial, and domestic water wells; Hardrock=mineral exploration tests, in piedmont/blue ridge;

Triassic=triassic basin holes; Oiltest=oil and gas exploratory holes.

Deci-long: decidegrees of longitude

Deci-lat: decidegrees of latitude

Summary

One hundred twenty-eight oil and gas test wells have been drilled in North Carolina. One hundred twenty-five wells have been abandoned in compliance with the Oil and Gas Conservation Act of 1945. The two wells drilled in 1998 are shut-in (completed but not in production) and both under a bond of $5,000 each. We do not know the method used to abandon the 1925 Craven County well.

For the 125 oil and gas test wells that have been plugged and abandoned, a paper folder for each test well is maintained by the DLR in secured filing cabinets at the NCGS Raleigh Field Office and Core Repository. Documents in each file include copies of permits, correspondences between the permittee and DLR, inspection reports by NCGS staff and documentation on the release of the bond, copies of the mud log, daily drilling reports and copies of all geophysical logs collected from the test well. By law, the test well files are to be kept confidential for one year, which can be extended to two years at the request of the permit holder. At this time, all documents are public records and can be viewed or copied by anyone. To arrange access to the oil and gas test well files, contact the NCGS.

J. Management of naturally occurring radioactive materials (NORMs)

Note to the reader: *This subsection was written with the assistance of the N.C. Department of Health and Human Services, Radiation Protection Section.*

Shale is a fine-grained sedimentary rock composed mostly of clay-size particles that settle out of a water column in a bay or deep ocean. Shale is a clastic sedimentary rock, which means it is made of tiny particles of weathered rocks and minerals. The two most resistant minerals to weathering are quartz and feldspar. In addition to the quartz and feldspar e more dense heavy minerals such as magnetite, ilmenite, zircon, pyroxene and amphibole can be incorporated into shale. Several types of pyroxene, amphiboles, feldspar and ziron are mildly radioactive.

Naturally occurring radioactive materials (NORMs) contribute to background radiation. Uranium (U) and Thorium (Th) are two of the most common radioactive elements that occur in most igneous, metamorphic and sedimentary rocks, in very low concentrations of 1 to 3 parts per million (ppm). These elements together with their decay daughters – Radium (Ra) and Radon (Rn) – have been associated with NORMs.

NORMs occur in both flowback and produced waters, because elements extracted from the shale or present in the formation water are brought up when flowback and produced water return to the surface. Each shale play appears to have a different pattern and range of levels for NORMs.[252] The existence of radioactivity in flowback water has been a major concern of environmental groups, particularly in the Marcellus shale play.[253] The U.S. EPA estimates that about 30 percent of oil and gas production sites have radionuclide levels of regulatory concern.[254]

The principal concern for NORMs in the oil and gas industry is that, over time, radiation can become concentrated in field production equipment, as sludge or sediment inside tanks and process vessels that have an extended history of contact with formation water, or in landfills in which sludge is disposed.[255] To address this concern, the Pennsylvania Department of Environmental Protection (DEP) conducted a study starting in 1991 to survey more than 400 oil and gas well sites, nine pipe yards and about 500 miles of dirt road that were sprayed with brine for dust suppression.[256] Their survey shows that about 60 percent of the well sites had readings at or below background levels. Thirty-four percent of the readings were within 10 microroentgens per hour (microR/hr) of background, and two percent were 21-54 microR/hr above background.[257] The level of background radiation varies, but from their evaluation, 94 percent of the sites were at or only two to three times background levels.

[252] Groat, C.G., Grimshaw, T.W. (2012) Fact-based regulation for environmental protection in shale gas development, The Energy Institute, The University of Texas at Austin, February 2012. http://energy.utexas.edu/ Regulations report is: ei_shale_gas_regulations120215.pdf
[253] Ibid.
[254] Otton, J. K., Zielinski, R.A. (2000) Simple techniques for assessing impacts of oil and gas operations on Federal Lands – a field evaluation at Big South Fork National River and Recreation Area, Scott County, Tennessee (online edition), USGS Open-File Report 00-499, 51 pp.
[255] Ground Water Protection Council and ALL Consulting, 2009.
[256] PA DEP (1991 and 1995) NORM Survey Summary was prepared as an article in April 1995 for the IOGA News. An earlier NORM Survey Summary was prepared September 1, 1992. File accessed from PA Oil and Gas Commission website.
[257] Ibid.

Several states have adopted regulations for NORMs. Louisiana, Texas, Arkansas and Michigan have set an action level of 50 microR/hr for contamination. The level for Mississippi is 25 microR/hr.[258] Federal limits have not yet established.[259]

The U.S. Geological Survey has documented cases of NORM contamination with measured radium isotopes at oil and gas exploration and production sites in Oklahoma, Illinois, Kentucky, Wyoming, and Michigan.[260] As part of the USGS field investigations of sites on federal land, personnel measured radioactivity from gamma rays produced by the decay products of $_{226}$Ra (principally $_{214}$Bi) and $_{228}$Ra (principally $_{208}$Tl), but also gamma rays from $_{40}$K.

N.C. Geological Survey (NCGS) measurements and sampling

Under the legislatively mandated study, the NCGS borrowed two hand-held radiation counters to measure outcrops of shale rock in the Deep River and Dan River basins. Samples were also collected to be sent to geochemical laboratories for analysis of a full geochemical package of 63 elements, which has a uranium and thorium detection and limit of 0.1 parts per million.

The fieldwork occurred on a handful of days over several months. Roadcuts and quarry walls were sampled for radioactivity with the handheld meters, and rock samples were collected for split samples to test for total organic carbon and elemental isotope radiation. While geochemical analysis is not yet complete, the field measurements were use the same method as Otton and Zielinski.

Drs. Kenneth Taylor and Jeff Reid of the NCGS were joined by Dr. Paul Olsen of Columbia University to take 54 measurements of the radioactivity of shale rock from the black shale Cows Branch Formation in the Dan River Basin along a 1,500 feet east-west exposure of the west pit in the Cemex Quarry north of Eden. Sites along the south-facing quarry wall were selected by Olsen and Taylor in order to sample all the darkest shale layers in the continuous section.

Taylor took two radiation measurements at each sampling location and Reid logged the measurement on a handheld GPS receiver with antenna. The locations were post-process by personnel in the North Carolina Geodetic Survey. The radiation measurements were reported in microR/hr.

The background radiation level was 6 to 10 microR/hr. Seven samples were at or equal to background: one sample at 9 microR/hr, four samples at 10 micro$/hr and two samples at 10.5 microR/hr. The highest value was 29 microR/hr (one value). The mean of the 54 samples has a radiation value of 14.8 microR/hr with a standard deviation of 3.7 microR/hr. Taking a level of 8 microR/hr as background, 19 samples are two times background and only one sample is greater than three times background. A plot of the observed radiation levels is shown in Figure 4-10.

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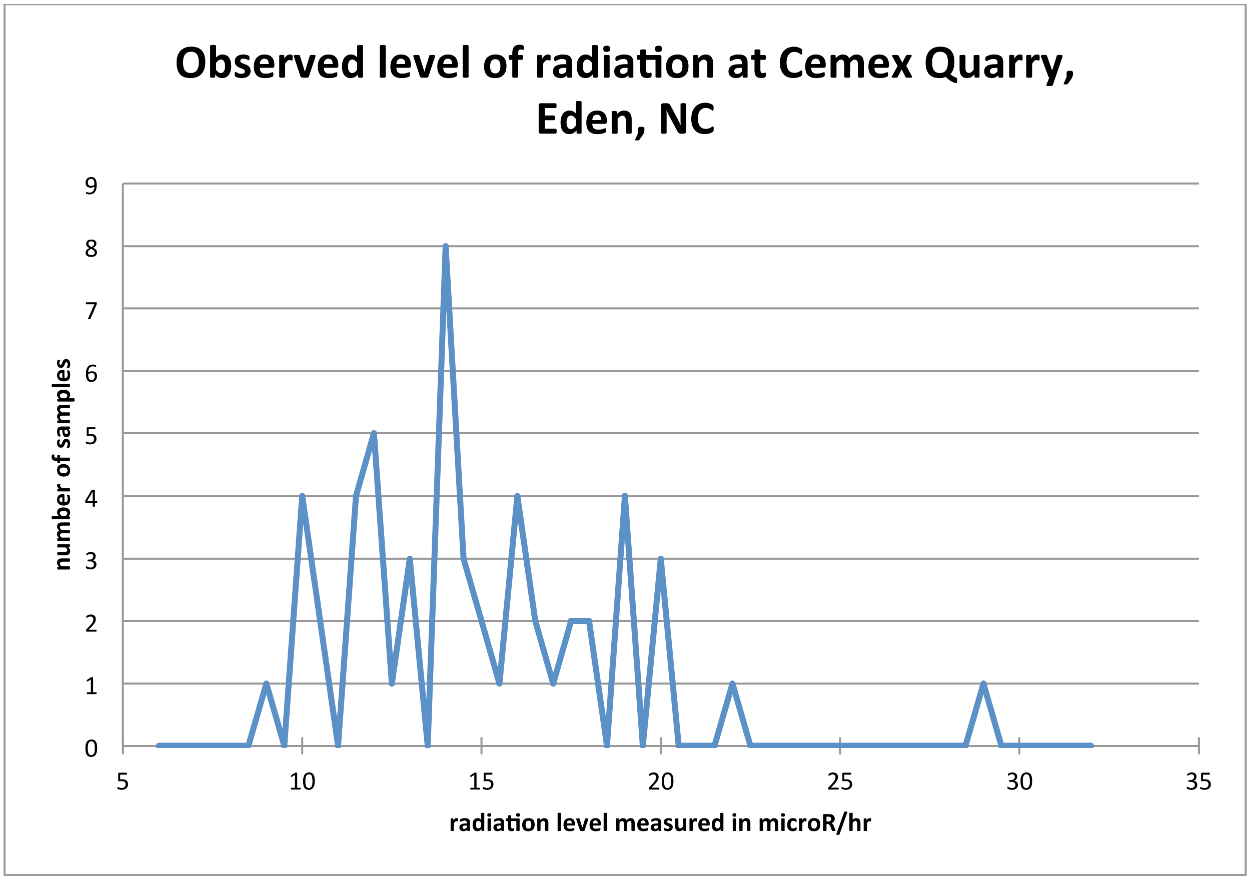
[258] Ibid.
[259] Groat and Grimshaw (2012) and Shale Gas Primer (2009).
[260] Otton and Zielinski (2000).

Figure 4-10. Observed radiation from shale rock along the south-facing quarry wall at the CEMEX mine north of Eden, N.C. The 1,500 foot quarry face is a continuous exposure of the Cows Branch Formation in the Dan River Basin.



K. Potential for increased seismic activity

This sub-section outlines the documented cases of increased seismic activity due to activities associated with oil and natural gas extraction. The full range of induced seismic activity from hydraulic fracturing to events triggered by deep-well disposal will be discussed. Actions taken by state and local governments to curtail the induced seismicity and prevent triggering of seismic events will also be outlined.

Earthquakes 101

An earthquake is a sudden motion or trembling of the earth caused by the abrupt release of slowly accumulated strain.[261] Each step increase in the Richter scale correlates to a tenfold increase in amplitude of ground shaking.[262] For example, a Richter magnitude "3" has a ground

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[261]Bates, R. L. and J. A. Jackson (editors). *Dictionary of Geological Terms – Third Addition.* American Geological Institute, Garden City, NY, 1984.

[262] Baig, A. and T. Urbancic. "Magnitude determination, event detectability, and assessing the effectiveness of microseismic monitoring program in petroleum applications." CGEC Recorder, February 2010, pg 22-26.

motion, recorded on a seismograph, that is 10 times larger in amplitude than a Richter magnitude “2” earthquake at the same distance from the seismograph.

With colleagues at the California Institute of Technology, Richter also developed an energy relationship, which held that for each step on the Richter scale, there was a 30-fold increase the amount of energy released. This means that the energy in 30 magnitude “2” earthquakes equals the energy in one magnitude “3” event.

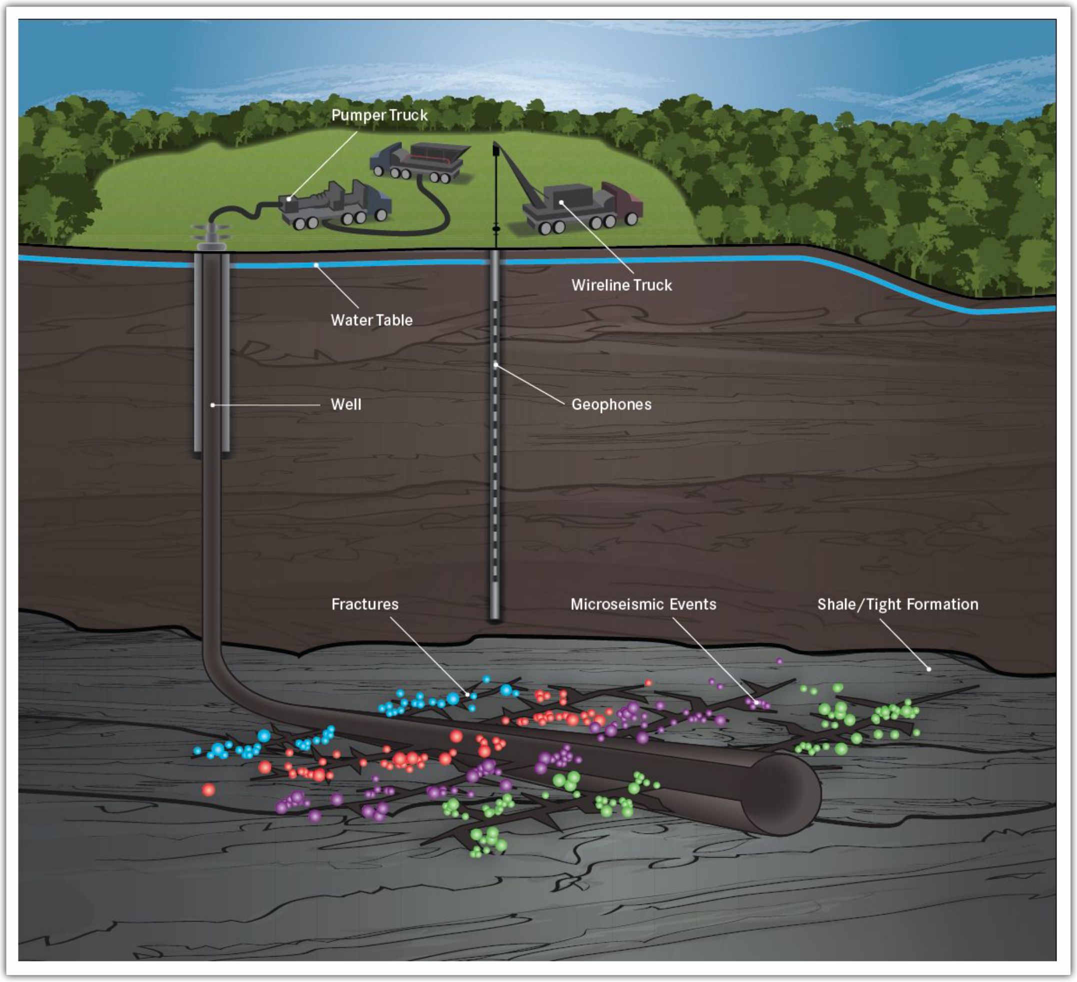
In the decades after the Richter scale was published, seismologists found that the magnitude scale saturated for large magnitude events, those greater than “7.3,” meaning that it is not recommended for use in large magnitude events. This led to the development of a magnitude scale that was directly related to the size of the rupture caused the earthquake. The moment magnitude was also able to give a quantifiable value to large explosions, such as underground nuclear tests.

The moment magnitude scale is open-ended and earthquakes can range from the smallest at “-4” to the largest which are greater than magnitude “9”. The smaller the earthquake, the higher the corner frequency, so to record successfully very small earthquakes, the data collection system must sample at rates of at least 10,000 samples per second.[263]

Does the process of hydraulic fracturing create earthquakes? The hydraulic fluid under pressure cracks the surrounding rock; these cracks generate vibrations while breaking and can be observed by sensitive geophones. Figure 4-11 shows the process of lowering a string of geophones from a wireline to record microseismic events produced by the cracking of the rock formation. These microseismic events have moment magnitudes in the range of “0.0” to “-2.5”.[264]

[263] Ibid.
[264] Ibid.

Figure 4-11. Colored spheres show the location of microseismic events generated by hydraulic fracturing.



Source: ESG Solutions. "Hydraulic fracture mapping." 2012.[265]

Baig and Urbancic (2010) show that these microseismic events, which are recorded on a geophone string closer than 1,600 feet away, must have a moment magnitude of at least "-1.8." In terms of energy, an event of that size is 30 times smaller than a "-0.8." event and 21.87 billion times smaller than a "5.8." For reference, the Aug. 23, 2011, Mineral, Va. earthquake was moment magnitude "5.8" and it shook Raleigh and was felt along the East Coast from Georgia to Canada.[266]

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[265] https://www.esgsolutions.com website.
[266] USGS. "Magnitude 5.8 – Virginia – 2011 August 23 17:51:04 UTC." *Significant Earthquakes 2011.* 2011. Retrieved from: http://earthquake.usgs.gov/earthquakes/eqinthenews/2011/se082311a/.

Possible case of seismicity induced by hydraulic fracturing

The Oklahoma Geological Survey (OGS) in 2011 investigated a citizen report of feeling several earthquakes during the night at a location of a nearby hydraulic fracturing project.[267] Looking at seismograms for that day, about 50 earthquakes occurred during that time. Only 43 earthquakes were large enough to be located and the magnitudes ranged from 1.0 to 2.8 using the duration magnitude. Using the relation given earlier for the size of the microseisms created during hydraulic fracturing, these events are 900 to 27,000 times smaller than the felt earthquakes. The OGS analysis showed that shortly after hydraulic fracturing began, small earthquakes started occurring. Most of these earthquakes occurred within a 24-hour period after the hydraulic fracturing operations had ceased.[268] The OGS shows a strong correlation in both time and space as well as a reasonable fit to a physical model suggesting a possibility that these earthquakes were induced by hydraulic fracturing.

Several instances of induced earthquakes have been documented in the scientific literature. These include the Rocky Mountain Arsenal; Rangely, Colo.; Paradox Valley, Colo.; and the KTB Deep Well in Germany.[269] In each of these cases, strong correlations exist between the onset of fluid injection and the start of seismicity. There were also correlations between the well location and the location of the seismicity which tended to be in close proximity to the well.[270]

The final correlation criteria require that there must be changes in fluid pressure at the depth of the earthquakes sufficient to encourage seismicity. In the case of the OGS investigation, the first fracture stage (between 9,830 and 10,282 vertical feet below the surface) was at an average rate of injection of 88.5 barrels per minute and at an average injection pressure of 4,850 pounds per square inch (psi). The earthquakes were about 1.5 miles away from the well and co-located with a group of small fault-bounded blocks.

Arkansas case of disposal wells inducing earthquakes

A swarm of small earthquakes started occurring near the town of Guy in north-central Arkansas in September 2010. The several thousand earthquakes migrated from the northeast to the southwest along a seven to nine mile linear trend over the next several months. On Feb. 27, 2011, a magnitude 4.7 earthquake occurred near the town of Greenbrier. To the south and east of Guy is the community of Enola, a place with a history of earthquake activity. In 1982, over a period of a few weeks, thousands of small earthquakes were recorded near there. Again in 2001, the ground began to shake again when more than 2,000 events occurred that year.[271]

In March of 2011, two natural gas companies, Chesapeake Energy and Clarita Operating, agreed to temporarily suspend use of an injection wells for wastewater disposal in central Arkansas

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[267] Holland, Austin. "Examination of Possible Induced Seismicity from Hydraulic Fracturing in the Eola Field, Garvin County, Oklahoma." Oklahoma Geological Survey, Open-File Report OF1-2011.
[268] Ibid.
[269] Ibid.
[270] Ibid.
[271] U.S. Geological Survey. 2010-2011 Arkansas earthquake swarm Poster. http://earthquakes.usgs.gov/earthquakes/eqarchivees/poster/2011/20110228ARupdate.medium.jpg, published March 1, 2011.

where the earthquakes persisted.[272] The companies stopped operations of the wells near Greenbrier and Gay only five days after the Greenbrier quake struck.

The Arkansas Oil and Gas Commission undertook an investigation and discovered that four disposal wells were located on a fault line: the northeast to southwest extension of the New Madrid Seismic Zone. After two of the four wells stopped operating in March, the number of earthquakes sharply declined. A public hearing was held on July 26, 2011, and two draft orders were circulated to first request an immediate cessation of disposal operations and order the plugging of the disposal well; and second, request an immediate moratorium on any new or additional class II commercial disposal wells or class II disposal well permits in certain areas.

Lawrence E. Bengal, director of the Arkansas Oil and Gas Commission, issued those two orders on Aug. 2, 2011.[273,274] That moratorium closed one disposal well and had the direct effect of closing three other disposal wells in the 1,150 square mile area. A map of the moratorium area can be found on the Arkansas Oil and Gas Commission web site.[275]

Ohio and another case of induced seismicity

Trucks have been transporting produced water to Ohio from the Pennsylvania gas fields since the Pennsylvania DEP asked drillers to stop disposing of flowback water at municipal wastewater treatment plants. Across Ohio, there were underground injection wells for wastewater disposal that would accept another state's waste. That all changed when a magnitude 4.0 earthquake struck the Youngstown-Warren area in Ohio on the last day of 2011.[276]

By Jan. 3rd, press reports quoted Dr. John Armbruster of Columbia University's Lamont-Doherty Earth Observatory saying that the earthquake and the 11 minor earthquakes that followed it were due to the wastewater well.[277] What many did not know was that more than two weeks earlier, Henry Fountain from *The New York Times* had reported that eight earthquakes in eight months had already struck the region and the experts who Mr. Fountain quoted in his article had already suspected that there was a connection between the earthquakes and the disposal

[272] Eddington, S. "'Fracking' disposal sites suspended, likely linked to Arkansas earthquakes." Associated Press published by *Huffington Post* at www.huffingtonpost.com, March 3, 2011.

[273] Arkansas Oil and Gas Commission. "Request for an immediate cessation of disposal operations and order to plug a Class II Commercial Disposal Well." Order No. 180A-1-2011-07, August 2, 2011.

[274] Arkansas Oil and Gas Commission. "Request for an immediate moratorium on any new or additional Class II commercial disposal well or Class II disposal well permits in certain areas." Order No. 180A-2-2011-07, August 2, 2011.

[275] Arkansas Oil and Gas Commission. "Permanent Disposal Well Moratorium Area Map," Scale 1:300,000, compiled by Ramsey, J. 6/7/2011, Map date 6/20/2011.

[276] Associated Press. "Earthquake strikes in northeastern Ohio near Youngstown." December 31, 2011, 3:57 PM, updated: December 31, 2011, 5:56 PM.

[277] Sheeran, T. "Expert: wastewater well in Ohio triggered quakes." Associated Press, January 3, 2012.

well.[278] Mark Niquette from Bloomburg News reported that while Ohio had stopped operations at five wells, the state's other 177 disposal wells would continue to be used.[279]

After researching the link between the seismic events in the Youngstown area and a brine disposal well, the Ohio Department of Natural Resources developed new standards for transporting and disposing of brine. The new requirements include a prohibition against drilling new wastewater disposal wells in the Precambrian basement rock formation, pressure and volume monitoring devices including automatic shut-off switches and electronic data recorders, and requiring that brine haulers install electronic transponders to ensure monitoring of all shipments.[280]

In addition, press reports from West Virginia also suggested a correlation between seismicity and disposal wells in that state.[281] Andrew Maykuth from the *Philadelphia Inquirer* reported on January 14, 2012 that the Columbia University team had been invited to Youngstown, Ohio in 2011 and they had installed four seismographs near the well in November.[282]

Summary

The process of hydraulic fracturing causes microseismic events that do not pose a threat to the environment or human health or safety. Most reports of significantly increased seismicity have occurred in regions where disposal wells are operated and related to underground injection of waste rather than hydraulic fracturing. Only a small fraction of those operations are inducing seismicity. Limiting injection volumes, decreasing pressure, and distributing the waste between more disposal wells have been shown to reduce and even eliminate induced seismicity, while reusing and recycling of wastewater can reduce the need for other waste management options. Based on these considerations, we recommend that the state maintain its prohibition on underground injection of wastewater due to North Carolina's unsuitable geology for wastewater injection and seismic risks.

L. Disposal, storage and transportation of hazardous and non-hazardous solid waste

Under both state and federal law, there is normally a clear dividing line in the management of hazardous and non-hazardous solid waste. With respect to oil and gas drilling wastes, the

[278] Fountain, H. "Quakes add to rumblings over hydraulic fracturing." Raleigh *News and Observer*, December 13, 2011.
[279] Niquette, M. "Ohio quake spurs action on 5 wells, won't stop oil and gas work." *Bloomburg News*, January 4, 2012.
[280] LoParo, Carlo. "Ohio's New Rules for Brine Disposal Among Nation's Toughest." Ohio Department of Natural Resources. March 9, 2012. Retrieved March 12, 2012 from http://www.ohiodnr.com/home_page/NewsReleases/tabid/18276/EntryId/2711/Ohios-New-Rules-for-Brine-Disposal-Among-Nations-Toughest.aspx.
[281] Steelhammer, R. "Small earthquake rattles Braxton near quake cluster recorded in 2010." *West Virginia Gazette*, January 11, 2012.
[282] Maykuth, A. "Quakes focus scrutiny on fracking." Raleigh *News and Observer*, January 14, 2012.

picture is much less clear because wastes that may be classified as hazardous waste are not regulated as hazardous waste under the primary federal law.

As defined in the federal Resource Conservation and Recovery Act (RCRA), hazardous waste is a solid waste that may

> "(i) Cause, or significantly contribute to, an increase in mortality or an increase in serious irreversible, or incapacitating reversible illness; or
>
> (ii) Pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, disposed of or otherwise managed."[283]

A solid waste is a hazardous waste if it is not excluded from regulation as a hazardous waste and meets any of the following conditions:

- It exhibits any of the characteristics of a hazardous waste (ignitable, corrosive, reactive or toxic).
- It has been named as a hazardous waste and appears on one of four lists in the regulations.
- It is a mixture containing a listed waste and a non-hazardous waste; or
- It is a waste derived from the treatment, storage or disposal of a listed hazardous waste.

Federal hazardous waste regulations include the following exclusion: "The following solid wastes are not hazardous wastes: Drilling fluids, produced waters, and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy."[284] EPA guidance "does not preclude these wastes from control under state regulations, under the less stringent RCRA Subtitle D solid waste regulations, or under other federal regulations.[285]

In some instances, drilling fluids and liquids used to fracture the shale contain additives that are hazardous materials. Spills or releases of chemicals used in exploration and production can occur as a result of tank ruptures, equipment or surface impoundment failures, overfills, vandalism, vehicle accidents or improper operations. In the instance of a chemical spill, the cleanup could produce wastes that have a hazardous component (such as contaminated soils) that would not be considered exempt from RCRA and may require handling as a hazardous waste.

While chemical additives used in drilling may still be regulated as hazardous wastes, drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy are exempt under the EPA regulatory

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[283] 40 CFR 261.10(a)
[284] 40 CFR 261.4(b)(5)
[285] U.S. Environmental Protection Agency, Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations, EPA530-K-01-004, www.epa.gov/osw/nonhaz/industrial/special/oil/oil-gas.pdf

decision cited above. Although large quantities of fluids are needed during exploration and production of natural gas, industry reports indicate that much of this fluid can be recycled. Section 4C discusses the alternatives for disposal of any remaining process wastewater. This section will address disposal of other wastes and the particular challenge of handling waste streams that do not neatly fit into the standard categories of hazardous and non-hazardous waste.

For the state of North Carolina to appropriately regulate exploration and production waste, the state must know the chemical makeup of all fluids used during hydraulic fracturing. The composition of fracturing fluids varies from company to company; the geology of the area being drilled may also require adjustments in the fracturing formula. Natural gas companies performing hydraulic fracturing activities are not required under federal law to identify the chemical composition of the hydraulic fracturing fluid. This information is necessary in order to determine how to treat and dispose of any fluid waste from the hydraulic fracturing process.

In 2009 the New York State Department of Environmental Conservation (NYSDEC) produced a document that lists 12 classes of additives used in the shale fracturing process. A “sample fracture fluid composition by weight” from this report is presented in Table 4-13.

Table 4-13. Sample of Hydraulic Fracturing Fluid Composition by Weight

Additive Class	Fluid Composition by Weight
Acid	0.110%
Breaker	0.010%
Bactericide/Biocide	0.001%
Clay Stabilizer/Controller	0.050%
Corrosion Inhibitor	0.001%
Crosslinker	0.010%
Friction Reducer	0.080%
Gelling Agent	0.050%
Iron Control	0.004%
Scale Inhibitor	0.040%
Surfactant	0.080%
pH Adjusting Agent	0.010%

This NYSDEC report discusses how each product within the 12 classes of additives may be made up of one or more chemical constituents. This report presents “a list of chemical constituents and their Chemical Abstract Service (CAS) numbers that have been extracted from complete produce chemical compositional information and Material Safety Data Sheets (MSDS) submitted to the NYSDEC for nearly 200 products used or proposed for use in hydraulic fracturing operations in the Marcellus Shale area of New York.” This list contains more than 250 compounds and classes of compounds (i.e. Petroleum Distillates, Aliphatic Acids, Aromatic Hydrocarbons). Only a handful of these chemicals would be used in a single well, but the list demonstrates the variety of chemicals that may be utilized.

It is important to know the types of chemicals being used both to ensure appropriate disposal of any waste and to be prepared for emergency response. A number of states have required disclosure of compounds used in fracturing fluids. In some states, the driller only has to disclose the information to the state regulatory agency. Other states also require public disclosure. In either case, any proprietary information would need to be protected.

Since exploration and production wastes include some wastes that may have the characteristics of hazardous wastes, but are not regulated under RCRA because of the federal exemption, oil and gas-producing states have generally developed specific standards for handling exploration and production wastes that fall somewhere between RCRA hazardous waste rules and the less stringent standards applied to typical industrial and household waste. North Carolina does not have standards that specifically address disposal of or transportation of exploration and production waste.

Solid Waste regulations 15A NCAC 13B .0105 address that the collector is responsible for the satisfactory collection and transportation of all solid waste to a permitted disposal site or facility and that only solid wastes which the site or facility is permitted to receive. Vehicles or containers used for the collection and transportation by whatever means, including but not limited to, highway, rail, and navigable waterway, of garbage, or refuse containing garbage, need to be covered, leakproof, durable, and of easily cleanable construction, cleaned as often as necessary to prevent a nuisance or insect breeding and maintained in good repair. Vehicles or containers used for the collection and transportation of any solid waste need to be loaded and moved in such a manner that the contents will not fall, leak, or spill and need to be covered when necessary to keep contents dry and to prevent blowing of material. If spillage should occur, the material shall be picked up immediately by the solid waste collector and returned to the vehicle or container and the area shall be properly cleaned.

- It is recommended that hauler certification or manifest standards, such as those required by several other states or within hazardous waste regulations, be studied to determine if additional regulations are needed.

State law defines “solid waste” to include the non-oil components of exploration and production such as the drilling muds and cuttings. [286] Under state rules, solid wastes that are not RCRA hazardous wastes may go into an industrial landfill designed and constructed for that particular waste or to a municipal solid waste (MSW) landfill.

Since North Carolina statutes and rules have not been written to address these particular types of wastes, existing state rules would allow disposal of all RCRA-exempt exploration and production wastes (other than oils and liquid hydrocarbons) in a MSW landfill. North Carolina has strong standards for design and construction of both industrial and MSW landfills, but those standards were not developed for disposal of hazardous waste. As a result, disposal of exploration and production wastes, that may be classified as hazardous absent federal exemption, may present some risks that MSW landfills may not have been designed to manage. The nature of these wastes may also cause landfill operators to refuse to accept the waste even

[286] The definition excludes oils and other liquid hydrocarbons.

if state law continues to allow disposal in an MSW landfill. A landfill operator can exclude wastes that would otherwise be allowed for disposal; wastes that are difficult to handle or perceived to pose an unusual risk may be turned away.

Solid waste types known to be generated in the shale gas industry

The majority of waste produced in the shale gas industry is liquid. Liquids are not allowed in landfills. Types of industrial solid waste include:

- Drilling muds that pass the paint filter test
- Drill cuttings unless the drill cuttings are radioactive regulated waste
- Waste water residuals
- Produced sand
- Spent filters and filter media that do not contain oil
- Soils contaminated due to spill or leaks, but not hazardous waste
- Pipe rust, scale and other deposits

Available types of solid waste disposal in North Carolina

Hazardous waste disposal facilities

Currently there are no commercial hazardous waste disposal facilities in North Carolina. The Division of Waste Management oversees the operation of 10 commercial hazardous waste management facilities that store and treat hazardous waste. Commercial hazardous waste facilities are permitted to store hazardous waste from offsite sources and could be permitted to accept wastes generated by shale gas exploration and production. Although the facilities currently operating in North Carolina are not disposal facilities, they are responsible for ensuring that the waste is disposed properly.

Industrial landfills

Industrial landfills receive specific types of industrial waste. At present, there are only three types of industrial landfills in North Carolina; coal combustion residuals produced by the electric power industry; battery-related wastes; and wastewater sludge and boiler ash from the paper industry. Twelve out of 13 industrial landfills are located at the facility where the waste is generated; the landfill space is used by the permitted landfill owner or operator, who is usually also the waste generator. The one exception is a Halifax County facility that accepts coal combustion residuals from small regional power companies.

Industrial landfills – siting, construction and operation regulatory requirements
Industrial landfills are sited, constructed and operated according to North Carolina sanitary landfill regulations 15A NCAC 13B .0503 and .0504. These regulations require that industrial landfills must have a design that requires a leachate collection system, a closure cap system and a composite liner system consisting of two components: the upper component is a flexible membrane (30 ml minimum) and the lower component is a two-foot (minimum) compacted soil

with a hydraulic conductivity of no more that 1 x 10-7 cm/sec. An applicant may also prove through modeling that an alternative landfill design can meet state groundwater standards at the compliance boundary. Industrial landfill modeling must include hydrogeologic characteristics of the facility and surrounding lands, the climatic factors of the area, and the volume and physical and chemical characteristics of the leachate.

- **Recommendation:** Exploration and production waste should only be allowed in a landfill with a liner and leachate system that meets the standard for a MSW landfill. Since modeling of the waste would only evaluate and design for one snapshot of waste type; an alternative landfill design based on that modeling would not adequately account for the variety of chemicals used in the industry.

  Modeling of the exploration and production waste within the current regulations would only evaluate and provide a design for one chemical makeup of waste. This type of model would not compensate for the variety of chemicals used presently in the industry and would not allow industry to evolve and vary the industrial process and henceforth the wastes. This will also be necessary given the proprietary nature of the shale gas industry concerning the types of chemicals in use in the drilling muds and fracturing fluids.

In addition to preventing leachate from contaminating groundwater at the compliance boundary, state rules establish siting and design criteria to prevent landfill impacts on floodplains, threatened and endangered species, archaeological or historic sites, parks, recreational or scenic areas, and state nature or historic preserves. Other standards address potential explosion hazards and impacts to surface waters.

Landfill sites must also maintain buffers between the disposal areas and certain features:

- A 50-foot minimum buffer between all property lines and disposal areas
- A 500-foot minimum buffer between private dwellings and wells and disposal areas
- A 50-foot minimum buffer between streams and rivers and disposal areas

Municipal solid waste landfills

In North Carolina presently there are 40 landfills that are allowed to take nonhazardous solid waste. MSW landfills are constructed with leachate collection systems and one of three regulatory liners or an alternative liner design with equivalent protection from leakage and with modeled groundwater protection. These municipal solid waste landfills are sited, constructed and operated under N.C.G.S. 130A-295 and regulations 15A NCAC 13B .1601 through .1637. The siting criteria are more stringent than the industrial landfill siting criteria.

MSW landfills are allowed to take all types of non-hazardous wastes with the exception of petroleum wastes. Other possible options are available for handling petroleum contaminated soils from spills or leaks associated with exploration and production, such as management by land application through the Division of Waste Management - Underground Storage Tank Section or use as fuel in brick kilns.

Possible waste-handling problems associated with the shale gas industry

Naturally occurring radioactive materials (NORM) - NORM has been shown to be present within shale formations of the Triassic Basins. Section I of this report describes the types of wastes that may include radiation. It is possible that accumulation of waste with undetectable levels of radiation will cumulatively cause detectible radiation in a landfill. Levels of radiation would have to be closely monitored at the landfill to ensure safe levels are maintained. If radiation were found, the landfill would have to cease accepting the cuttings and possibly move existing radioactive waste. That determination would be made by the Radiation Protection Section of the North Carolina Department of Health and Human Services. Waste from oil and gas exploration and production activities would thereafter have to be taken to a low-level radioactive disposal site.

Occurrence of NORM because of the prevalence of radioactivity in some rock formations has been a cause of concern at MSW landfills. Drill cuttings from water supply wells have sometimes caused the radioactivity meter at a landfill to react. (More often, radioactivity detected at a landfill has originated from medical waste.) Operational plans for permitted landfills include procedures for responding to radiation detection at the landfill. The initial action taken involves the facility and/or the DWM contacting the Department of Health and Human Services - Radiation Protection Section, in order to effectively and safely isolate and dispose of radioactive waste.

- **Recommendation:** Industrial and MSW landfill's operational plans should be required to include radiation monitoring at the working face of the landfill when exploration and production waste is being accepted.

Hazardous wastes - Solid Waste landfills cannot accept RCRA hazardous waste. MSW landfills are responsible for screening the waste received to exclude any hazardous waste from disposal. As noted above, exploration and production wastes present some special challenges. Some types of chemical-contaminated wastes and waste materials that are not exclusive to the oil and gas industry but used in the manufacturing of natural gas (such as battery or paint waste) continue to be classified as RCRA hazardous waste and cannot be disposed of in a MSW landfill. As noted above, many oil and gas wastes (such as drill cuttings) are exempt from RCRA regulation as a hazardous waste. North Carolina law would not currently prohibit disposal of those wastes in a MSW landfill. The fact that the waste does not have to be handled as a hazardous waste does not mean that it is an acceptable solid waste for disposal in a MSW landfill.

Difficult to handle wastes - Landfill operators are not required to unconditionally accept all wastes that could be lawfully disposed of at the landfill. The nature of the exploration and production industrial wastes may cause the landfill operator to turn the waste away, even if it is not hazardous. Shale cuttings are the consistency of very fine clay or silt; the cuttings may be difficult to handle and may also cause the landfill to experience operational problems. Large slugs of shale cuttings, when placed in an MSW landfill, could create a layer of relatively impermeable waste. This layer could may a "perching" effect in which the leachate (liquid that has percolated through or drained from the landfill waste) stays on top of the cuttings. If the leachate exerts pressure on the side slopes of the landfill, a failure of the side slopes may result in contaminants leaving the landfill.

Industrial landfills do not at this time receive solid waste disposal fees. If the shale gas industry chooses to site a landfill in North Carolina, it is recommended that fees be assessed for this type of waste at commercial industrial landfills. It is not recommended that the tax be assessed at industrial landfills that are located at the facility that generates the waste.

Possible compromise of landfill components – There has not been research on the possible interaction between chemicals used in industrial processes (such as natural gas production) and other wastes in MSW landfills and possible effects on the liner or leachate components. The possibility of the chemical solutions compromising the landfill integrity must be thoroughly assessed before these exploration and production wastes are allowed into existing or new landfills. DENR should undertake at least literature study to determine if design or operational changes are needed for this particular waste stream.

Section 5 – Potential economic impacts

Note to the reader: *Subsections A through F of Section 5 were prepared by the N.C. Department of Commerce. Subsections G through N of Section 5 were prepared by the N.C. Department of Environment and Natural Resources.*

A. Introduction

The purpose of this section is to provide an estimate of economic impacts on the North Carolina economy related to new gas drilling activities, specifically directional drilling of gas wells in the Sanford sub-basin of the Deep River Triassic Basin. The economic impact analysis focuses on drilling activities and does not take site preparation, leasing of land, hydraulic fracturing, or extraction, production or transmission of gas into consideration. While a review of the natural gas industry was conducted in order to potentially model these impacts, uncertainty about data quality did not permit further analysis. Data quality issues resulted primarily from a lack of survey-based, real-world industry cost and supply chain relationship data. This survey approach would be necessary due to the absence of well-defined data in the matrix that underlies the modeling tool. Follow-on analysis with better data is recommended.

This analysis is not intended to indicate a position by the North Carolina Department of Commerce (Commerce) for or against the drilling, extraction, production or any other activities related to natural gas development in the state.[287] Results are estimates and are derived from inputs provided by the North Carolina Department of Environment and Natural Resources (N.C. DENR) and, in some cases, based on forecasts or hypotheses. While economic modeling can provide some information about how an economy will react under different conditions, future economic performance is not entirely predictable. Economic modeling should be used in conjunction with other forms of analysis to estimate overall project merits and drawbacks. Caution must be exercised in interpreting these results; the economic impact estimates in this analysis are based strictly upon assumptions.

Commerce uses IMPLAN software for economic impact modeling.[288] The following table summarizes data and assumptions used in developing the economic impact model for this report.

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[287] The natural gas industry includes other "midstream" economic activities such as extraction, processing, distribution and retail sales. These activities are not analyzed in this report, nor were economic analyses of these activities requested by the study legislation.

[288] IMPLAN allows researchers to develop local level input-output models to estimate the economic impacts associated with marginal changes in the economy, such as "shocks" of new production or output. The framework and methodological basis for the IMPLAN model is derived from the U.S. Dept. of Commerce's Benchmark Input-Output Accounts. The IMPLAN model is widely used by local, state and federal government agencies as well as private industry and universities. Minnesota IMPLAN Group Inc. or MIG Inc. was founded in 1993 by Scott Lindall and Doug Olson as an outgrowth of their work at the University of Minnesota starting in 1984. This developmental work closely involved the U.S. Forest Service's Land Management Planning Unit in Fort Collins, and Dr. Wilbur Maki at the University of Minnesota. For more information please visit www.IMPLAN.com.

Table 5-1. Model Assumptions

Project Location / Economic Impact Area	North Carolina
IMPLAN Sector	28 - Drilling Oil and Gas Wells
Time Period for Drilling Activities	2013-2019
Estimated Cost of Drilling a Single Well	$3,000,000
Total Estimated Wells Drilled	368
Local Purchase Percent	Using model default values, 36% of drilling expenditures are expected to be spent in the local economy

In addition to the model described below, a literature review of studies published both by the natural gas industry as well as by academic economists was conducted to better understand potential outcomes for North Carolina. Overall, these studies show that a large infusion of economic activity from shale gas drilling will increase the incomes of some individuals and communities and will add jobs. However, without reliable expenditure inputs based on primary research, it remains uncertain how much wealth, income or benefits from long-term employment would accrue to Lee, Chatham and surrounding counties.[289] Some literature questions whether static input-output models (like IMPLAN) overestimate potential economic impacts and suggests dynamic models like REMI are more suitable alternatives.[290] Although this economic impact analysis only considers impacts and jobs associated with new drilling activities, readers should not discount the potential for additional economic impacts associated with other natural gas activities such as site preparation, leasing of land, production, extraction or transmission. Data and modeling tool limitations are the primary reasons these analyses were not included here. Lease payments, for example, were not modeled due to lack of reasonable data including the volume and amount of potential payments.[291]

The following analysis considers the economic impacts of new drilling activities in the Sanford sub-basin on the North Carolina economy. The Sanford sub-basin is approximately 59,000 acres

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[289] Primary research through firm surveys would provide a better baseline from which to forecast. At this time, the oil and gas extraction industry is underdeveloped in North Carolina. Surveying would likely yield inadequate sample results, and would have been impossible to conduct given the time constraints on this analysis.

[290]Regional Economic Models Inc. REMI's primary difference from IMPLAN is that it is a dynamic model. Changes in the economy are measured by their marginal, not average, impact on the environment. This reasoning is intuitive because the relationships and impacts of economic changes are not linear. REMI is able to account for a wide variety of factors that are absent in IMPLAN. This includes demographic information, substitution between different resources, trade impacts and changes in productivity. More information is available online at www.remi.com

[291] A study by the America's Natural Gas Alliance notes lease payments range from "as little as $150 per acre to as high as $5,000 per acre…without specific data, such a wide range poses a significant problem in approximating the aggregate lease payments made for a specific year."

of the 785,000 acres of the Triassic Basins in North Carolina (this does not include the Pekin formation because of its lack of potential to produce hydrocarbons). Table 5-2 summarizes annual figures for the total number and estimated cost of wells drilled. The number of wells and the drilling ramp-up estimates were provided by the North Carolina Geological Survey. Estimates for the average cost to drill a single well were confirmed by industry experts consulted by Commerce including the American Natural Gas Alliance. Costs can vary from well to well. In total, 368 wells are assumed to be drilled over seven years.

Table 5-2. Potential Well Field

Sanford Sub-basin Shale Play: Estimated Number of Wells			
	Annual Ramp Up	*Cummulative Total*	*Annual Cost of Drilling*
Year 1	7	7	$ 21,000,000
Year 2	32	39	$ 96,000,000
Year 3	45	84	$ 135,000,000
Year 4	63	147	$ 189,000,000
Year 5	88	235	$ 264,000,000
Year 6	123	358	$ 369,000,000
Year 7	10	368	$ 30,000,000
These estimates were forecasted by N.C. DENR based on the estimated acreage of the Sanford sub-basin and using an estimated well spacing of one well per 160 acres.			

Limits to economic input-output models

IMPLAN models are customized to reflect existing economic relationships within a local economy. Thus, given that the state currently has no shale gas hydraulic fracturing, extraction or production activities, baseline data in IMPLAN is limited. Until the industry is more developed, and economic and multiplier relationships are better represented in the data, model outputs will not be robust.

B. Economic impacts

The model estimates that 36 percent of drilling investments will be provided by North Carolina vendors. Since North Carolina does not presently have a developed fossil fuel extraction industry, the majority of inputs for drilling operations are not expected to be supplied by existing North Carolina companies. This means there are likely to be substantial economic "leakages" as dollars are spent outside the North Carolina economy on purchases for operations. For instance, the drilling and hydraulic fracturing of wells for the purpose of extracting shale gas requires specialized equipment. Several aspects of this process could be contracted to specialized companies.

Impacts are presented as statewide impacts. Monetary figures are presented in 2012 dollars. IMPLAN software measures employment in job-years.

Key Economic Impact Definitions

Direct Impacts: The known or predicted change in the economy that is being studied. In this analysis the direct impacts are the changes associated with drilling activities.

Indirect Impact: Secondary impact caused to industries in the supply chain of the direct impact. In this case, indirect impacts would result from industries supplying resources and materials to drilling activities.

Induced Impact: Direct and indirect employment (and increases in labor income) creates additional household spending on goods and services.

Employment: The number of full-time and part-time jobs; measured by place of employment. Employees, sole proprietors and active partners are included, but unpaid family workers and volunteers are not.

Job-Years: IMPLAN measures employment impacts in job-years with each unit of employment equivalent to one job for one year. This is important when IMPLAN is used to measure non-permanent operations. For example, IMPLAN does not distinguish between 10 units of employment employed over five years, and 50 workers employed in one year. Therefore, one worker may account for multiple units of employment if that person is employed over multiple years.

Output: Output includes the cost of production or the cost of goods sold plus value added (employee compensation, proprietor income, indirect business taxes and other property income).

Value Added: is a measure of the contribution of each private industry and of government to a region's gross domestic product. It is defined as an industry's gross output (which consists of sales or receipts and other operating income, commodity taxes, and inventory change) minus its intermediate inputs (which consist of energy, raw materials, semi-finished goods, and services that are purchased from domestic industries or from foreign sources).

Employment

The IMPLAN model estimates drilling activities in the Sanford sub-basin would sustain an average of 387 jobs per annum over the seven-year time period. This figure includes all direct, indirect and induced jobs and is an annual average calculated from the total effects in Table 5-3. An alternative way to express this is that drilling activities would result in approximately 2,710 "job-years"[292] over the seven-year period modeled. The true annual job counts will vary by year, depending on the level of drilling activity; these detailed impacts are shown below in Table 5-3. Using the well drilling ramp-up estimated by the North Carolina Geological Survey, there will be differing numbers of wells drilled in any given year and, consequently, varying

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[292] IMPLAN measures employment impacts in job-years with each unit of employment equivalent to one job for one year. An individual worker may account for multiple units of employment if that person is employed over multiple years. So, for example, 2,710 cumulative jobs could mean 2,710 jobs each lasting one year or 271 jobs each lasting 10 years, or other potential combinations of jobs and years equaling 2,710 total job-year units over the time period.

levels of employment associated with drilling. In the peak well year, drilling activities are estimated to sustain 858 jobs over a one-year period. In Year 1, the year with the lowest level of drilling expenditures, the IMPLAN model estimates that 59 jobs will be either created or partially supported by these expenditures.

It is important to recognize that the jobs associated with these projects are not permanent and continuous jobs, but rather temporary jobs. When the drilling expenditures cease, or the maximum number of wells have been drilled, all employment demands created by the gas resource associated with drilling will end. Table 5-4 details the top 10 industry sectors most affected by the new drilling activities. The Drilling Oil and Gas Wells sector is most impacted, with nearly 1,800 job-years, 65 percent of the total, estimated to be added.

Table 5-3. Annual Employment Impacts

Annual Employment Impacts (Job Years)				
Year	Direct Effect	Indirect Effect	Induced Effect	Total Effect
2013	39	6	15	59
2014	169	28	64	261
2015	229	38	87	353
2016	308	51	117	475
2017	413	68	157	638
2018	555	92	210	858
2019	44	7	17	68
Cummulative	1,760	290	670	2,710

Source: MIG IMPLAN 3.0; model created February 2012. Cumulative employment impacts rounded to the nearest tenth.

Table 5-4. Top 10 Industry Sectors Impacted

Top Ten Industry Sectors Impacted from, Ranked by Employment		
Sector	Description	Total Employment (Job Years)
28	Drilling oil and gas wells	1,757
413	Food services and drinking places	82
360	Real estate establishments	55
319	Wholesale trade businesses	45
394	Offices of physicians, dentists, and other health practitioners	35
369	Architectural, engineering, and related services	33
397	Private hospitals	30
367	Legal services	29
335	Transport by truck	27
398	Nursing and residential care facilities	26

Source: MIG IMPLAN 3.0; model created February 2012. Employment impacts rounded to the nearest whole number.

Financial impact to the state's economy

Each year, as long as the drilling activities continue to occur, the state's economy will experience positive economic benefits. Table 5-5 describes the estimated annual impacts on the state's gross domestic product.

Table 5-5. Annual Economic Impacts

Value Added (GDP)				
Year	Direct Effect	Indirect Effect	Induced Effect	Total Effect
2013	$ 4,833,000	$ 562,000	$ 1,026,000	$ 6,421,000
2014	$ 21,236,000	$ 2,468,000	$ 4,508,000	$ 28,212,000
2015	$ 28,703,000	$ 3,336,000	$ 6,093,000	$ 38,131,000
2016	$ 38,623,000	$ 4,489,000	$ 8,198,000	$ 51,310,000
2017	$ 51,853,700	$ 6,027,000	$ 11,007,000	$ 68,888,000
2018	$ 69,662,000	$ 8,097,000	$ 14,787,000	$ 92,546,000
2019	$ 5,551,000	$ 645,000	$ 1,178,000	$ 7,374,000
Cummulative	$ 220,461,700	$ 25,624,000	$ 46,797,000	$ 292,882,000

Source: MIG IMPLAN 3.0; model created February 2012. All monetary impacts presented in 2012 dollars and rounded to the nearest thousand.

Cumulative impacts of the drilling activities are reported and expected to occur over the time period 2013-2019. Upon exhaustion of all drilling activities in the state, it is estimated the economy will have increased output by $453 million. Output represents the level of all economic activity from production and is typically larger than value added impacts, which measure the direct change in North Carolina's gross domestic product (GDP). Anticipated drilling activities are estimated to positively affect the state's GDP by $292 million by year 2019. Value-added is considered a standard benchmark in measuring economic impacts on the state.

C. Timing of the realization of economic benefits

One indicator of the likelihood that North Carolina's basin will be developed in the near-term would be for this resource to appear in shale play lists from leading energy research firms. IHS Global Insight, in a December 2011 study for the American Natural Gas Alliance, considered 21 geographically diverse shale plays around the country.[293] Six prominent plays are expected to account for more than 90 percent of U.S. shale capacity by 2035. North Carolina was not on this list and, at this time, does not appear on U.S. Geological Survey maps of North American shale plays. In the meantime, the Energy Information Administration's preliminary 2012 *Annual Energy Outlook*[294] assumes that with increased production, average annual wellhead prices for natural gas remain below $5 per thousand cubic feet (2010 dollars) through 2023.

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[293] HIS Global Insight, Inc. "The Economic and Employment Contributions of Shale Gas in the United States." December 2011. Web http://anga.us/media/235626/shale-gas-economic-impact-dec-2011.pdf

[294] U.S. Energy Information Administration *Annual Energy Outlook 2012 Early Release Energy Consumption by Sector and Source. 23 Jan. 2012.* http://www.eia.gov/forecasts/aeo/er/

If gas prices stay low for the short- to medium-term, it is not likely that investors will act to develop North Carolina's resource because costs would outweigh returns on investment. At today's prices wet gas has been a more attractive resource than dry gas. In addition, the fossil fuel industry is highly agglomerated, meaning that suppliers cluster in the same geographic region as the extraction activities. Due to North Carolina's lack of infrastructure, including suppliers, the state's natural gas resource is likely to be less economically attractive than others.

D. Other issues

Agriculture, wineries and the local food industry

As shown in the model, natural gas development is expected to create benefits, as equipment, materials and supplies are purchased by the natural gas industry and workers spend their wages in the local economy. Landowners could realize benefits from lease royalties and payments. Research from other states indicates that there are also potential costs to local agricultural activities. Natural gas extraction is an equipment-intensive heavy industry. It has been associated with disruption of farmland and viticulture with round-the-clock operations, noise, lights, wastewater pits and significant truck traffic on remote roads, according to studies from Cornell University.[295]

Lee and Chatham counties are relatively developed with little activity in the Agriculture, Forestry and Fishing industry sector. In 2011 (Q1), there were 91 agriculture establishments in Lee County and none in Chatham.[296] These data do not capture smaller farm activity in the counties; Chatham has an active Cooperative Extension Service, which reports at least 11 small farms in the county.[297] In 2010, 0.4 percent of Lee County residents were employed in agriculture.

Residential issues

Some analysts report that elsewhere in the country, a natural gas and oil development boom has caused the demand for available housing stock to outpace supply due to imported labor (workers with specialized skills in drilling and hydraulic fracturing). For areas like North Carolina, with potentially few workers trained in the fossil fuel extraction industry, companies are likely

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[295] Community and Regional Development Institute at Cornell University. "The Economic Consequences of Marcellus Shale Gas Extraction: Key Issues" Issues 14 September 2011 Web. http://assembly.state.ny.us/member_files/125/20110915/index.pdf

[296] BLS data downloaded from the North Carolina Department of Commerce Access NC website, http://accessnc.commerce.state.nc.us/EDIS/page1.html

[297] Growing Small Farms, Chatham County Cooperative Extension. Web. http://www.ces.ncsu.edu/chatham/ag/SustAg/index.html

to bring in work crews from elsewhere.[298] Some researchers have found that the uptick in housing demand from this industry is associated with increases in housing prices.[299]

North Carolina residents have expressed concern at public forums about the impacts of increased housing prices on retirees. About 13 percent of Lee County residents, 22 percent of Moore County residents and 17 percent of Chatham County residents are over 65 years old.[300] More than 70 percent of residents in Lee and Chatham counties own their homes. Rental unit vacancy rates in these two counties are relatively low,[301] which is an indicator of a limited rental housing supply. If significant gas development occurs, a shortage of affordable housing is possible. Because many retirees are on fixed incomes, increased housing prices may raise property tax rates and crowd out this population. Anecdotal observations also suggest that retirees may not wish to live in an industrialized landscape.

Travel and tourism

Travel and tourism are important parts of the present and future economy of North Carolina and the Piedmont region. Visitor spending encompasses a wide group of activities including the food and beverage industry, lodging, retail and service stations, transportation and recreation. North Carolina ranks as the sixth most visited state in the United States and enjoys $1.5 billion in visitor spending annually. North Carolina's natural scenic beauty, picturesque small towns, and rural vistas are hallmarks for the brand identity the State markets to visitors.

In 2010 (the most recent data available from the Department of Commerce Travel Economic Impact Model), direct visitor spending[302] in Lee, Chatham and Moore counties was an estimated $60.0 million, $25.0 million and $342 million respectively.[303] Approximately 0.6 percent of Lee County residents and 0.2 percent of Chatham County residents were employed in the Tourism industry in 2010.[304]

Based on the economic impact analysis shown here, monetary impacts (value added) from drilling could exceed tourism-related spending in a given year. Individual gas wells and drilling activity, while disruptive at a local scale, may not impact the region's tourism industry directly. Some economic developers would argue that tourism-related businesses are locally owned and

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[298] Jacquet, Jeffrey. "Energy Boomtowns & Natural Gas: implications for Marcellus Shale Local Governments & Rural Communities." Northeast Regional Center for Rural Development, Penn. State University, Paper No. 43. 1/2009. http://nercrd.psu.edu/publications/rdppapers/rdp43.pdf

[299] Williamson, Jonathan and Bonita Kolb. "Marcellus Natural Gas Development's Effect on Housing in Pennsylvania." Center for the Study of Community and the Economy, Sep. 31, 2011. Web. http://www.phfa.org/forms/housing_study/2011/marcellus_report.pdf

[300] Source: American Community Survey, 2006-2010

[301] American Community Survey 2006-2010 data downloaded from the North Carolina Department of Commerce Access NC website, http://accessnc.commerce.state.nc.us/EDIS/page1.html

[302] The North Carolina Commerce Department defines travel as activities, including business and leisure, associated with all overnight and day trips to places 50 miles or more, one way, from the traveler's origin and any overnight trips away from home in paid accommodations.

[303] NC Department of Commerce. Travel Economic Impact Model Web. http://www.nccommerce.com/tourism/research/economic-impact/teim

[304] BLS data downloaded from the North Carolina Department of Commerce Access NC website, http://accessnc.commerce.state.nc.us/EDIS/page1.html

operated, making these businesses important to the long-term economic development trajectory for a region. Some researchers have argued that the employment impact from gas drilling, comparatively, will be relatively short-term and the majority of economic benefits will not accrue to local businesses. [305]

E. Potential impacts to North Carolina energy consumers from developing the shale play

North Carolina customers should continue to benefit in the short-term from historically low natural gas prices nationwide, regardless of development of the potential supply in North Carolina. The New York Times reported Dec. 15, 2011 that Piedmont Natural Gas, a residential service provider in North Carolina, South Carolina and Tennessee, has filed to lower its customer rates eight times since 2008. As a result, Piedmont's average residential customer in North Carolina and South Carolina will pay approximately $175 less in wholesale natural gas costs this winter compared with 2008-09 and, collectively, residential customers in North Carolina and South Carolina will save approximately $125 million compared to that prior period.[306]

The low-cost benefits North Carolina customers enjoy in the future will likely occur as a result of macroeconomic factors, such as the current domestic oversupply, that contributed to the current suppression of prices. The development of the North Carolina shale play will not, in itself, dictate the price North Carolina customers pay for natural gas services. [307]

F. Fiscal impacts to local government

The arrival of a natural gas industry to central North Carolina will increase the need for services from local governments including infrastructure (especially roads), emergency, school and police and criminal justice services. Elected officials have testified to the Pennsylvania Association of Township Supervisors that dramatic increases in heavy truck traffic have

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[305] Rumbach, Andrew. "Natural Gas Drilling In the Marcellus Shale: Potential Impacts On the Tourism Economy of the Southern Tier." Web. http://www.stcplanning.org/usr/Program_Areas/Energy/Naturalgas_Resources/STC_RumbachMarcellusTourismFinal.pdf

[306] *The New York Times*. "Piedmont Natural Gas Files to Further Reduce Customer Rates in North Carolina and South Carolina," Dec. 15, 2012. Web 27 Feb 2012. http://markets.on.nytimes.com/research/stocks/news/press_release.asp?docTag=201112150948PR_NEWS_USPRX____CL23460&feedID=600&press_symbol=231886

[307] We note that some, notably Vik Rao of the Research Triangle Energy Consortium at RTI (http://rtec-rtp.org/2012/02/17/can-nc-profit-from-shale-gas-without-producing-it/), suggest that North Carolina may be able to profit from the shale boom without producing any natural gas locally. In a February 2012 blog post, Rao argues that if natural gas prices stay low most shale gas production will be in the regions, like the Marcellus, that have higher amounts of the more-profitable natural gas liquids (NGL). The NGL's can easily be processed into raw materials for many useful fabrics and plastics. Alternatively, nitrogen fertilizers use methane as the feed stock, so "cheap natural gas equates to cheap fertilizer," Rao says. North Carolina may be able to import cheap natural gas and liquids from neighboring states and turn attention to incentivizing manufacturing value-added products that use gas and liquids as inputs.

impacted the sense of place of rural communities, forced residents to combat increased traffic and caused local governments to face higher cost burdens from road maintenance.[308] However, North Carolina's Deep River Basin is significantly more populated than the regions that have reported negative impacts to local governments; the region has relatively higher industrial activity and the North Carolina well field is estimated to be much smaller. [309] Bradford County, Pa., currently has 1,994 Marcellus wells permitted, as of February 2012.[310] In contrast, the North Carolina Geological Survey currently estimates a maximum field of 368 wells in North Carolina's Sanford sub-basin.

Research studies on whether crime rates increase disproportionately in energy boomtowns are mixed. Recent findings from the Justice Center for Research at Pennsylvania State University observe that there has been a "more variable pattern" of calls to state police and arrest statistics in the Marcellus region; the report stresses, however, that given an abbreviated observation period, trends are "difficult to detect."[311] More information on the potential impacts of oil and gas extraction and production on crime can be found in Section 6.

Some regions have reported that an influx of well-paid oil and gas workers has caused problems in drilling communities, but it is difficult to predict whether these problems will occur in North Carolina. This economic impact analysis shows that the majority of workers will be employed in the drilling sector of the economy. According to IMPLAN 2010 data, North Carolina has fewer than 200 workers in the Drilling Oil and Gas Sector at present. Since North Carolina does not have a substantial workforce in the Drilling Oil and Gas Sector and the national drilling workforce is transitory by nature, the state can expect many of the drilling crews to come from other parts of the country.

G. Additional state resources needed to provide regulatory oversight

The emergence of the shale gas industry in North Carolina will require additional capacity within the Department of Environment of Natural Resources (DENR) and/or another regulatory agency to develop and enforce a "cradle to grave" regulatory program. DENR has delegated authority for implementing and enforcing many different federal laws that govern aspects of shale gas development - the Clean Water Act, the Clean Air Act, the Safe Drinking Water Act etc. The stay may also need to add additional environmental standards to fill gaps in existing state and federal laws. Multiple divisions within DENR and other agencies would be involved in

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[308] Herr, Elam. "Impact of Natural Gas Drilling on Infrastructure." Presentation for Pennsylvania State Association of Township Supervisors, June 8, 2011. Web http://files.dep.state.pa.us/PublicParticipation/MarcellusShaleAdvisoryCommission/MarcellusShaleAdvisoryPortalFiles/Workgroups/June_8_Elam_Herr.pdf

[309] Pad construction would involve heavy equipment including bulldozers and excavators. According to the New York Department of Environmental Conservation, well pads average 3.5 acres in size, with additional land required for surface water impoundments and equipment staging areas.

[310] See www.MarcellusGas.org for permit activity.

[311] Kowalski, Lindsay and Gary Zajac. "A Preliminary Examination of Marcellus Shale Drilling Activity and Crime Trends in Pennsylvania" Justice Center for Research at The Pennsylvania State University. January 9, 2012 Web. http://www.justicecenter.psu.edu/wp-content/uploads/2012/01/Marcellus-Shale-Drilling-and-Crime-Trends-in-Pennsylvania.pdf.

this regulatory framework due to the current division of jurisdiction over different aspects of the industry.

Specific shale gas regulatory activities undertaken by other states include:

- Issuing permits for drilling oil/gas wells
- Setting requirements for proper locations, well designs and construction of wells
- Inspection of drilling activity
- Development of controls and procedures to prevent accidental discharges
- Creation of design standards for on-site pits/lagoons to store drill cutting and flowback water
- Oversight of proper closure of on-site waste pits/lagoons after drilling completion
- Setting and enforcing standards for drill-cutting management and sediments left on-site
- Responding to citizen questions/concerns about safety of drinking water from private wells
- Customer service support for companies and individuals wishing to learn more about permitting processes and drilling regulations
- Production and dissemination of information and educational products to make the public aware of regulatory, landowner rights, public notices and other issues
- Regulation of the wastewater disposal and transportation activities

If North Carolina chooses to develop an oil and gas regulatory program, state government staff will undertake all of these types of activities. Drilling activities also will increase the need for staff to evaluate and monitor potential impacts to local plant and animal habitats and health and groundwater quality. As North Carolina has no active oil and gas production, DENR has no full-time staff members working on oil and natural gas permitting and regulation. The recent STRONGER report for North Carolina suggests that, at least initially, the department should focus resources on development and adoption of rules, technical criteria, administrative procedures, staff training, permitting processes and incorporation of industry considerations into state emergency response plans. These measures are needed to ensure that state environmental staff, the industry and the public are aware of regulatory expectations and permitting processes. These activities could influence workloads for administration, legal and rulemaking staff and numerous individuals in several DENR divisions.

Once preliminary tasks are finished, ongoing program activities in the Division of Waste Management, Division of Land Resources, Division of Water Quality, Division of Water Resources and Office of Conservation Planning and Community Affairs would continue to impact staff workloads. There may be additional effects to other divisions and agencies that we are unable to anticipate at this time. This additional staffing would be located in the department's main administrative office in Raleigh and in the regional office(s) closest to the drilling fields. The amount of staff needed to successfully implement the program and provide industry support will depend on the number of permit applications that need to be processed and the number of inspections the agency is required to perform.

Recent budget cuts have reduced the number of field inspectors in the Division of Land Resources. The water, air and waste programs have also lost staff positions due to the economic downturn and resulting loss of tax and permit revenue. These offices cannot handle the additional workload associated with natural gas exploration and development with the current staff level. While the state's environmental programs are strong, existing programs were not developed in anticipation of regulating oil and gas exploration and production activities. Development of a comprehensive permit review process, inspection program and emergency response plans will be critical to guard against potential negative environmental impacts and this program development will take time and resources beyond those necessary for existing program operations.

While it is premature to estimate what the development of a regulatory program would cost to develop and maintain, state agencies will need enough resources to comprehensively oversee and implement environment and natural resource protections against potential adverse industry impacts. This would include appropriate measurement of environmental baselines before gas extraction, monitoring water and air quality during drilling, and ensuring measures taken to close wells properly.

Arkansas, a state with oil, natural gas and shale gas industries, employs seven full-time positions for inspection and monitoring activities of its shale gas program. This includes four dedicated full-time inspectors, one supervisor and two enforcement administrators. Twelve additional positions in the Arkansas Department of Environmental Quality that have some job responsibilities relating to the shale gas industry.[312] According to the department's database, staff conducted 1,392 inspections on facilities involved in the Fayetteville Shale Gas industry. Each inspector performed about 200 inspections in 2011. In addition, the agency issued at least 815 permits for different drilling and support activities.[313]

A companion agency, the Arkansas Oil and Gas Commission, employs an additional 39 people to support all three energy industries. The Commission administers and enforces state and federal laws dealing with the regulatory oversight of the oil, natural gas and brine production industries in Arkansas. The Commission's regulatory programs include administration of the U.S. EPA Underground Injection Control Program for operation of underground injection disposal wells, the U.S. Department of Transportation (USDOT) Pipeline Safety Program for natural gas gathering lines and Arkansas Abandoned and Orphaned Well Plugging Program used to plug abandoned and orphaned oil and gas wells. Commission staff members have job titles such as general counsel, regulatory counsel, geologists, permitting specialists and administrative functions such as fiscal officer, GIS analyst, IT support and webmaster. A random sample of permit reports indicates that this agency issued around 23 permits each week during 2011. This is about 1,200 for the year.[314]

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[312] Personal communication with Doug Szenher, Public Outreach and Assistance Division, Arkansas Department of Environmental Quality February 24, 2012.

[313] Arkansas Department of Environmental Quality. Complaints and Inspections Database. Accessed 2/25/2012. http://www.adeq.state.ar.us/home/pdssql/complaints_inspections.asp.

[314] State of Arkansas Oil and Gas Commission. Weekly Permit and Completions Reports for 2011. Accessed February 28, 2012. http://www.aogc.state.ar.us/permitreport.htm

Pennsylvania, another state with an established gas and oil program, employs approximately 200 people in the Department of Environmental Protection to work with the gas and oil industries.[315] In 2011, 88 inspectors performed 24,194 inspections of oil and gas facilities. This is an average of 275 inspections per inspector each year. The agency processed 5,728 gas and oil related permits. Approximately 60 percent of the permits and 40 percent of the inspections occurred in the Marcellus Shale gas region.[316]

These figures serve as initial indicators for the number of additional staff that may be required in North Carolina to support an active oil and gas exploration and extraction industry. The number of staff needed to implement North Carolina's regulatory program would be dependent on the specific permit review and inspection requirements and level of industry activity. We are unable to create a more precise estimate for needed resources and staff at this time without knowing more about the specific permit and compliance requirements that will apply to the industry.

H. Comparison of existing bonding requirements to those in other states

Oil and gas producing states generally require oil and gas operators to provide a bond to the regulatory agency before beginning certain drilling operations. The U.S. Department of Interior's Bureau of Land Management imposes similar bonding requirements on oil and gas drillers operating on federal lands. These bonds are intended to ensure the operator properly reclaims the site after drilling; if the operator does not (or cannot), the bond provides the agency with funds to perform reclamation.

A 2010 Government Accounting Office (GAO) survey compiled data on expenditures by the federal Bureau of Land Management (BLM) to plug orphaned wells on BLM lands and compared bonding requirements across states.[317] The survey found that over a 21-year period, BLM spent about $3.8 million to reclaim 295 orphaned wells, or an average of about $12,900 per well. The GAO report states that "the amount spent per reclamation project varied greatly, from a high of $582,829 for a single well in Wyoming in fiscal year 2008 to a low of $300 for 3 wells in Wyoming in fiscal year 1994." The BLM also estimated the costs of wells it has yet to reclaim at approximately $1.7 million for 102 orphaned wells, an average of roughly $16,700 per well.

The GAO survey compared bonding requirements of the BLM with 12 western states. These states offer both a single well bond that covers one well and a blanket bond that covers either multiple wells or all wells of a single operator in a state. The amount of the bond required may vary based the number of wells the operator has orphaned or the well depth. A summary of

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[315] Personal communication with Eugene W. Pine, P.G., Environmental Program Manager, Pennsylvania Department of Environmental Protection February 29, 2012.

[316] State of Pennsylvania Oil and Gas Permits and Compliance Reports/Databases for 2011. Accessed February 29, 2012. http://www.portal.state.pa.us/portal/server.pt/community/oil_and_gas_reports/20297

[317] U.S. General Accounting Office. *Oil and Gas Bonds: Bonding Requirements and BLM Expenditures to Reclaim Orphaned Wells,* GAO-10-245. Washington, DC: General Accounting Office, 2010. Retrieved April 16, 2011 from http://www.gao.gov/assets/310/300218.pdf.

bonding requirements found in the survey is presented in Table 5-6. For some states, regulators may increase or decrease the amount of the bond based on various factors. For instance, Alaska has a minimum single well bond of $100,000 unless the operator demonstrates that the cost of well abandonment and location clearance will be less than $100,000.

Table 5-6. Summary of State Oil and Gas Well Bonding Requirements[318, 319, 320, 321]

State	Single Well Bond	Blanket Bond
Alaska*	≥$100,000	≥$200,000
Arizona*	$10,000 (≤10,000 ft) $20,000 (>10,000 ft)	$25,000 (up to 10 wells) $50,000 (11-50 wells) $250,000 (>50 wells)
California*	$15,000 (<5,000 ft) $20,000 (5,000-10,000 ft) $30,000 (≥10,000 ft)	Either $1 million **OR** $100,000 (up to 50 wells) $250,000 (>50 orphaned wells), + 1) annual fee for each idle well, or 2) escrow account of $5,000 per idle well, or 3) $5,000 bond per idle well, or 4) file a management and elimination plan
Colorado*	$10,000 (<3,000 ft) $20,000 (>3,000 ft)	$60,000 (up to 100 wells) $100,000 (>100 wells) Additional fees for "excess inactive wells"
Idaho*	≥$10,000	≥$25,000 Idaho has separate requirements for wells on state and school lands.
Montana*	$1,500 (≤2,000 ft) $5,000 (2,001-3,500 ft) $10,000 (>3,500 ft)	$50,000 (Board of Oil and Gas Conservation can increase bond to $100,000 under certain circumstances or limit number of wells covered)
Nevada*	≥$10,000	≥$50,000
New Mexico*	$5,000 plus $1 per foot of well depth in some counties $10,000 plus $1 per foot of well depth in all other counties	$50,000
Oregon*	$10,000 (<2,000 ft) $15,000 (2,000-5,000 ft) $25,000 (>5,000 ft)	sum of individual bonds but not <$100,000

[318] 25 Pa. Code § 78.303. Retrieved March 3, 2012 from http://www.pacode.com/secure/data/025/chapter78/chap78toc.html.
[319] Tennessee Department of Environment & Conservation. "Oil and Gas Well Permit." Retrieved March 3, 2012 from http://tn.gov/environment/permits/oilgas.shtml.
[320] 16 Tex. Admin. Code § 3.78. Retrieved March 3, 2012 from http://info.sos.state.tx.us/pls/pub/readtac$ext.TacPage?sl=T&app=9&p_dir=F&p_rloc=148268&p_tloc=14949&p_ploc=1&pg=2&p_tac=&ti=16&pt=1&ch=3&rl=78.
[321] W. Va. Code § 22-10-5. Retrieved March 3, 2012 from http://www.legis.state.wv.us/wvcode/code.cfm?chap=22&art=10.

Table 5-6, continued

State	Single Well Bond	Blanket Bond
Pennsylvania[+∞]	$4,000	For wells <6,000 feet: • $4,000/well (up to 50 wells, but no bond > $35,000) • $35,000 + $4,000/well (51 - 151 wells, but no bond > $60,000) • $60,000 + $4,000/well (151 - 250 wells, but no bond > $100,000) • $100,000 + $4,000/well (>250 wells, but no bond > $250,000) For wells ≥6,000 feet: • $10,000/well (up to 25 wells, but no bond > $140,000) • $140,000 + $10,000/well (26 - 50 wells, but no bond > $290,000) • $290,000 + $10,000/well (51 - 151 wells, but no bond > $430,000) • $430,000 + $10,000/well (>150 wells, but no bond > $600,000)
Tennessee[+]	$2,000	$10,000 for up to 10 wells
Texas[+]	$2 per foot of total well depth for each well	$25,000 (1-10 wells) $50,000 (11 to 99 wells) $250,000 (100 or more wells)
Utah*	≥$1,500 (<1,000 ft) ≥$15,000 (1,001-3,000ft) $30,000 (3,001-10,000ft) ≥$60,000 (>10,000 ft)	≥$15,000 (<1,000 ft) ≥$120,000 (>1,000 ft)
Washington*	≥$50,000 for most wells	≥$250,000
West Virginia[+]	$5,000	$50,000
Wyoming*	≥$10,000 (<2,000 ft) ≥$20,000 (>2,000 ft)	≥$75,000

∞ Legislation enacted in Pennsylvania in February 2012 raised bond fees from $2,500 for a single well and $25,000 for a blanket bod covering all of an operator's wells in the state. These requirements will be effective in early April 2012.
* Data from the GAO survey.
\+ Data from individual state's codes or websites, as shown in footnotes.

Alaska also has a Statewide Miscellaneous Land Use Bond. This $100,000 bond is usually carried by applicants for geophysical exploration permits.

North Carolina Session Law 2011-276 revised the amount of the bond required for an oil and gas drilling permit to $5,000 plus $1 per linear foot. Under North Carolina's law, the bond only covers proper closure and abandonment of the well. The bond does not cover the costs of restoring the surface of the site to pre-existing conditions or remediation of contamination caused by the drilling operation. Currently in North Carolina, site reclamation is addressed only through lease agreements; North Carolina's oil and gas regulations do not require a site reclamation bond to address contamination or other environmental impacts. Permanent damage to the site represents a loss not only to the property owner, but also a loss to the public in the form of contaminated groundwater and surface water, increased runoff, erosion and sedimentation, and other environmental damage.

I. Comparison of existing severance taxes to severance taxes or royalty payments in other oil and gas states

Under the North Carolina Oil and Gas Conservation Act, adopted in 1945, the state can assess on "each barrel of oil produced and saved a tax not to exceed five mills on each barrel." The tax revenue can only be used to pay the costs of administering the law. The same act also levies a tax on natural gas. The Department is authorized to assess "against each 1000 cubic feet of gas produced and saved from a gas well a tax not to exceed one-half mill on each 1000 cubic feet of gas."[322] This is 5/100 of a cent, $.0005 per 1,000 cubic feet of gas. These revenues are also to be used solely to pay the costs of administering the law.[323]

Like North Carolina, a handful of states assess a severance tax as a flat rate per unit of measure. Most states base the severance tax on the gross value (the amount of gas produced multiplied by the average price paid for that gas). However, the way in which states calculate "value" varies. Some states deduct certain items from the gross value or gross proceeds, such as production costs, ad valorem taxes or royalties paid. Texas offers a reduced tax rate of 0.0% to 7.4% of the market value of gas for high cost wells for 120 days or until the cumulative value of the tax reduction equals 50 percent of the drilling and completion costs for the well,[324] "depending on how the well's drilling and completion costs compare to the median cost of all High-Cost gas wells (previous State fiscal year)."[325] In Montana, producers may deduct from the calculation of the severance tax payment any natural gas produced that is used in the operation of the well. As a result, the severance tax of each state is not directly comparable to that of other states, because it is not the "effective rate" that a gas operator must pay.

Despite these variations, North Carolina has one of the lowest severance taxes in the nation. In fact, with the exception of those states that do not assess any severance tax, North Carolina's tax rate was the lowest of all states for which severance taxes were identified as part of this study. Maryland, New York and Pennsylvania do not assess severance taxes on the production of natural gas, however, Pennsylvania recently enacted a law imposing an "impact fee" on natural gas production, and New York assesses a "property type production tax" on the amount of natural gas produced.

Severance tax and corporate income tax rates are shown for 21 states in Table 5-7. Because of the variety of deductions available and differences in the ways in which states calculate the value of natural gas sold, these rates are not directly comparable; however, this table provides an idea of how these tax rates relate to one another.

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[322] N.C.G.S. § 113-387. Retrieved March 3, 2012 from http://www.ncleg.net/gascripts/statutes/statutelookup.pl?statute=113.
[323] Ibid.
[324] 16 Tex. Admin. Code § 3.101. Retrieved March 3, 2012 from http://info.sos.state.tx.us/pls/pub/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=3&rl=101.
[325] Texas Comptroller of Public Accounts. "Natural Gas Production Tax." *Texas Taxes.* Retrieved March 3, 2012 from http://www.window.state.tx.us/taxinfo/nat_gas/.

Table 5-7. Severance and Corporate Income Tax Rates for Various Natural Gas-Producing States[326]

State	Severance Tax Rate	Estimated Tax Paid on 1,000 mcf at \$2.44 per MMBtu	Estimated Primary Severance Tax Burden*	Dedicated Severance Tax Revenues	Corporate Income Tax Rate
Alaska	25%	\$625.25	25.00%	None	10 rates for increasing income (1 - 9.4%)
Montana	12.16%	\$304.12	12.16%	Counties, local governments, conservation, reclamation, remediation, schools	6.75% of taxable income
Alabama	2.00% + privilege tax (3.65% to 8%)	\$250.10	10.00%	None	6.5% of taxable income
Kansas	8.00%	\$200.08	8.00%	Local governments	4.00%
Texas	7.50%	\$187.58	7.50%	Schools	0.5% of the taxable margin
West Virginia	5.00% + \$0.047 per mcf	\$130.05	7.08%	Local governments, conservation, reclamation, remediation, Medicaid	7.5% of taxable income
Oklahoma	1.00% - 7.00%	\$175.07	7.00%	Local governments, conservation, reclamation, remediation, schools	6% of taxable income
Louisiana	\$0.164/mcf	\$164.00	6.56%	Local governments, conservation, reclamation, remediation	5 rates for increasing income (4% to 8%)
Wyoming	6.00%	\$150.06	6.00%	Local governments, conservation, reclamation, remediation, water development	None
North Dakota	\$0.1476/mcf	\$147.60	5.90%	Local governments, schools, water development	3 rates for increasing income (1.7% to 5.2%)
Arkansas	1.25% - 5.00%	\$125.05	5.00%	Roads	6 rates for increasing income (1% to 6.5%)
Colorado	2.00% - 5.00%	\$125.05	5.00%	Local governments, conservation, reclamation, remediation, schools, water development	4.63% of taxable income
Utah	3.00% or 5.00%	\$125.05	5.00%	Schools	5% of taxable income
Kentucky	4.50%	\$112.55	4.50%	Local governments	3 rates for increasing income (4% to 6%)
New Mexico	3.75%	\$93.79	3.75%	Local governments, conservation, reclamation, remediation	3 rates for increasing income (4.8% to 7.6%)
Tennessee	3.00%	\$75.03	3.00%	Local governments	6.5% of net earnings
Ohio	\$0.025/mcf + \$.005/mcf assessment	\$30.00	1.20%	Conservation, reclamation, remediation	Commercial activities tax, \$150 minimum
North Carolina	\$0.0005/mcf	\$0.50	0.02%	Administrative costs related to oil and gas management	6.9% of taxable income
Maryland	0	\$0.00	0.00%	N/A	8.25% of taxable income
New York	0	\$0.00	0.00%	N/A	6.5% of taxable income
Pennsylvania	None; impact fee = \$50,000 per well in 2012	\$0.00	0.00%	N/A	9.9% of taxable income

*For those states that charge a flat rate per mcf, the estimated primary severance tax burden was calculated by dividing the severance tax rate by the Henry Hub price for natural gas on Feb. 29, 2012 (\$2.50 per mcf, or \$2.44 per MMBtu).

[326] This table was compiled using two primary sources: Marshall University's *Taxation of Natural Gas: A Comparative Analysis,* and the Allegheny Conference on Community Development's *Benchmarking Pennsylvania: A Summary of Severance Taxes on the Natural Gas Industry* (retrieved March 4, 2012 from http://www.alleghenyconference.org/PEL/PDFs/NaturalGasSeveranceTax021009.pdf). Where these two sources differed, the website of that state's revenue department was consulted. Corporate income tax information was collected primarily from the following source: Federation of Tax Administrators. "Range of State Corporate Income Tax Rates (For tax year 2012 – as of January 1, 2012)." February 2012. Retrieved March 4, 2012 from http://www.taxadmin.org/fta/rate/corp_inc.pdf.

J. Use of special assessments

In addition to severance taxes, a variety of other taxes, fees and assessments may affect the oil and gas industry in any given state. These include corporate income taxes, real property taxes, personal property taxes, sales and use taxes, impact fees and permit fees. A few of these are discussed below, but this should not be considered an exhaustive list of all of the taxes and fees assessed at the state and local levels in all states.

Corporate income taxes

Although Pennsylvania had no severance tax or impact fee on natural gas extraction until February 2012, the corporate income tax in Pennsylvania, at 9.9 percent of taxable income, was the highest corporate income tax of the 21 states examined. Wyoming is the only state that does not charge a corporate income tax. Corporate income tax rates also vary; however, corporate income taxes may not be as important a consideration as severance taxes, "as most gas operating companies are organized as exempt entities."[327] The way in which states determine taxable income varies. In nine states, the corporate income tax applies to a percentage of taxable income. Other states use tiered rates, depending on the level of income. In lieu of a corporate income tax, Texas levies a franchise tax of 0.5 percent of the taxable margin.

Pennsylvania's impact fee

On Feb. 8, 2012, Pennsylvania enacted legislation (House Bill No. 1950) that places an impact fee on each well drilling for natural gas in the Marcellus Shale. The fee will fluctuate from year to year based on current natural gas prices and the Consumer Price Index. In 2012, drillers will pay $50,000 per well (or $10,000 for vertical wells). The fee will be collected and administered by the Pennsylvania Public Utilities Commission, but a county may receive a share of the revenue if the county passes an ordinance enacting the fee by mid-April 2012. If a county fails to act, the municipalities within the county can pass a resolution in support of the impact fee. If more than half of a county's municipalities do so within 60 days, the county's fee will be enacted. The fee will also go into effect if municipalities representing more than 50 percent of the county's total population pass the resolution. In areas where the fee is in effect, 60 percent of the revenue would be split between the county and municipalities where the well is located, and the remainder would be divided among various state agencies. In addition, the bill "authorizes the annual transfer of millions of dollars from the Oil and Gas Lease Fund to the Environmental Stewardship Fund and Hazardous Sites Cleanup Fund."[328] Pennsylvania impact fee bill authors estimate the fee will generate about $180 million in 2012.

New York's property tax on natural gas

New York is unique in the way it taxes natural gas production. In the 1990s, New York's Office of Real Property Tax Services (ORPTS) was authorized by law "to impose an annual charge on oil

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[327] Marshall University Center for Business and Economic Research. *Taxation of Natural Gas: A Comparative Analysis*. 2011. Retrieved March 3, 2012 from http://www.marshall.edu/cber/research/NaturalGasFinal.pdf.
[328] StateImpact. "What the New Impact Fee Law Means for Pennsylvania." 2012. Retrieved March 4, 2012 from http://stateimpact.npr.org/pennsylvania/tag/impact-fee/.

and gas producers to pay costs incurred in the administration of the oil and gas program."[329] ORPTS develops economic profiles, using data submitted by oil and gas producing companies, the New York State Department of Environmental Conservation and a consulting geologist. Staff analyzes the data and "determines unit of production values for each economic profile. Assessors use the unit of production values to calculate assessed values for oil and gas properties."[330] The process involves an income approach to valuation of oil and gas wells that includes production decline rates and income/expense escalation rates, gross income and operating expenses, remaining economic life of property, real property taxes, net income, depreciation, depletion, income and other taxes, capital investment, royalty interest not retained, rate of return and calculation of the present worth of net income.

Real property taxes

A study by Marshall University's Center for Business and Economic Research examined the property valuation of natural gas property in 19 natural gas-producing states, finding that only two of the states (Alabama and Wyoming) do not levy a real property tax on natural gas. For the states that do assess a real property tax on natural gas, seven of them provide guidance to counties on how to value natural gas real property. Three allow local governments to determine the valuation methods and rates to be used as well as whether to tax natural gas real property.

Sales and use taxes

In the study performed by Marshall University, 17 states assessed sales and use taxes on natural gas. Alaska and Ohio do not. These taxes range from 1.5 percent (Mississippi) to 8.6875 percent (New Mexico). Five states allow local governments to levy a local sales and use tax in addition to the state's tax.

Other fees and taxes

Arkansas levies both a severance tax (ranging from 1.5 to 5 percent of the market value of gas) and a charge not to exceed 10 mills per thousand cubic feet of gas "to pay the expenses and other costs in connection with the administration" of the law laying out the activities of the Oil and Gas Commission.[331] The duties of the Arkansas Oil and Gas Commission include collecting data; performing inspections; examining properties, leases, papers, books and records; examining, checking, testing and gauging oil and gas wells, tanks, refineries and means of transportation; holding hearings; recordkeeping; enforcement activities; and making rules.[332]

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[329] The New York State Department of Taxation and Finance. "Overview Manual for Valuation and Assessment of Oil and Gas Producing Property in New York State." 2012. Retrieved March 4, 2012 from http://www.tax.ny.gov/research/property/valuation/oilgas/overview.htm.

[330] The New York State Department of Taxation and Finance. "Overview Manual for Valuation and Assessment of Oil and Gas Producing Property in New York State." 2012. Retrieved March 4, 2012 from http://www.tax.ny.gov/research/property/valuation/oilgas/overview.htm.

[331] Ark. Code § 15-71-107. Retrieved March 5, 2012 from http://law.justia.com/codes/arkansas/2010/title-15/subtitle-6/chapter-71/15-71-107/.

[332] Ark. Code § 15-71-110. Retrieved March 5, 2012 from http://law.justia.com/codes/arkansas/2010/title-15/subtitle-6/chapter-71/15-71-110/.

Utah levies a conservation tax of 0.2 percent on the value at the well of natural gas produced, saved and sold or transported from the place where it is produced. These fees are deposited into the Utah Oil and Gas Conservation Account, which is dedicated to the administration of the fund, the plugging and reclamation of abandoned oil and gas wells, and education programs addressing issues of the mineral and petroleum resources and industries.[333] Wyoming also has a conservation tax on the fair market cash value of all natural gas produced, sold and transported within the state. The Wyoming Oil and Gas Commission can adjust the rate as necessary, and the most recent rate is 0.04 percent.[334]

Colorado levies an environmental tax of 1.7 mills per $1 of the market value of natural gas at the wellhead, regardless of whether the gas was produced, saved, sold or transported from the field where it was produced. This funding supports the Colorado Oil and Gas Conservation and Environmental Response Fund. A portion of Colorado's severance tax may also support this fund[335] as well as any appropriations by the General Assembly, grants, etc. The fund was created to

> "(I) Investigate, prevent, monitor, or mitigate conditions that threaten to cause, or that actually cause, a significant adverse environmental impact on any air, water, soil or biological resource;
>
> (II) Gather background or baseline data on any air, water, soil, or biological resource that the commission determines may be so impacted by the conduct of oil and gas operations; and
>
> (III) Investigate alleged violations of any provision of this article, any rule, or order of the commission, or any permit where the alleged violation threatens to cause or actually causes a significant adverse environmental impact."[336]

Louisiana imposes an oilfield site restoration fee at a rate of $0.003 per thousand cubic feet of natural gas. This fee is increased for stripper and incapable wells to reflect the proportion of the reduced severance tax that would be collected.[337] Similarly, Texas levies an Oilfield Cleanup Fee on Gas of $0.0007 per thousand cubic feet of gas. The revenue is used in various conservation efforts, including controlling and cleaning up oil and gas waste, plugging abandoned wells, and conducting environmental site assessments.[338] Texas also levies a condensate production tax, at 4.6 percent the market value of gas in Texas.[339]

Mississippi levies drilling, permit and ownership transfer fees to fund its Oil and Gas Conservation Fund. The permit fee is $600 and the ownership transfer fee is $100. An

[333] Marshall University, December 7, 2011.
[334] Marshall University, December 7, 2011.
[335] Marshall University, December 7, 2011.
[336] Colo. Rev. Stat. § 34-60-124. Retrieved March 5, 2012 from http://cogcc.state.co.us/RR_Docs_new/rules/AppendixV.pdf.
[337] Marshall University, December 7, 2011.
[338] Marshall University, December 7, 2011.
[339] Texas Comptroller of Public Accounts. "Natural Gas Production Tax." *Texas Taxes.* Retrieved March 3, 2012 from http://www.window.state.tx.us/taxinfo/nat_gas/.

additional $100 annual tax on non-plugged natural gas wells funds Mississippi's Emergency Plugging fund.[340]

New Mexico has an Oil and Gas Conservation Tax, and an Oil and Gas Emergency School Tax. The Oil and Gas Conservation Tax is 0.19 percent of the taxable value of products sold. The Oil and Gas Emergency School tax is a privilege tax on the business of every person severing oil and other liquid hydrocarbons, carbon dioxide, helium and natural gas, and is based on the products' taxable value. For natural gas, this tax is four percent of the taxable value.

Proposed legislation in New York would establish a natural gas production contamination damage recovery and remediation fund. The fund would be charged as a surcharge on permit fees and could be used by the New York Department of Environmental Conservation "to pay for cleanup and decontamination costs incurred in any response to contamination due to natural gas production after funds from bonds established for this purpose are fully expended."[341]

Tennessee's oil and gas reclamation fund is supported by fees from violations of oil and gas extraction standards. The funds are used to perform reclamation work for lands and waters damaged by surface and subsurface exploration and extraction.[342]

K. Estimate of revenue generated by severance taxes or royalties at levels comparable to other oil and gas states

Since many states use the value of natural gas sold as the basis for severance taxes but calculate the value of natural gas differently, direct comparison of the revenue generated by these taxes is difficult. Table 5-8 shows examples of what some states collected in severance taxes in 2009.

[340] Marshall University, December 7, 2011.
[341] DiNapoli, Thomas, New York State Comptroller. Memorandum. OSC #20. Retrieved March 5, 2012 from http://www.osc.state.ny.us/legislation/2011-12/oscb20memo.pdf.
[342] Marshall University, December 7, 2011.

Table 5-8. Severance Tax Collections per Million Cubic Feet for 2009[343]

State	Severance Taxes Collected	Production (MMcf)	Taxes Collected per MMcf
Alaska	$77,141,000.00*	397,077	$194.27
Louisiana	$282,430,592.09†	3,332,956	$84.74
North Dakota	$9,811,808.26	59,369	$165.27
Ohio	$2,069,704.00†	88,824	$23.30
Oklahoma	$707,296,658.00†	1,857,777	$380.72
Tennessee	$1,252,875.55†	5,478	$228.71
Texas	$1,407,739,109.00	7,284,520	$193.25
West Virginia	$75,948,588.59	264,436	$287.21

† Fiscal Year 2009

* Calendar Year 2008

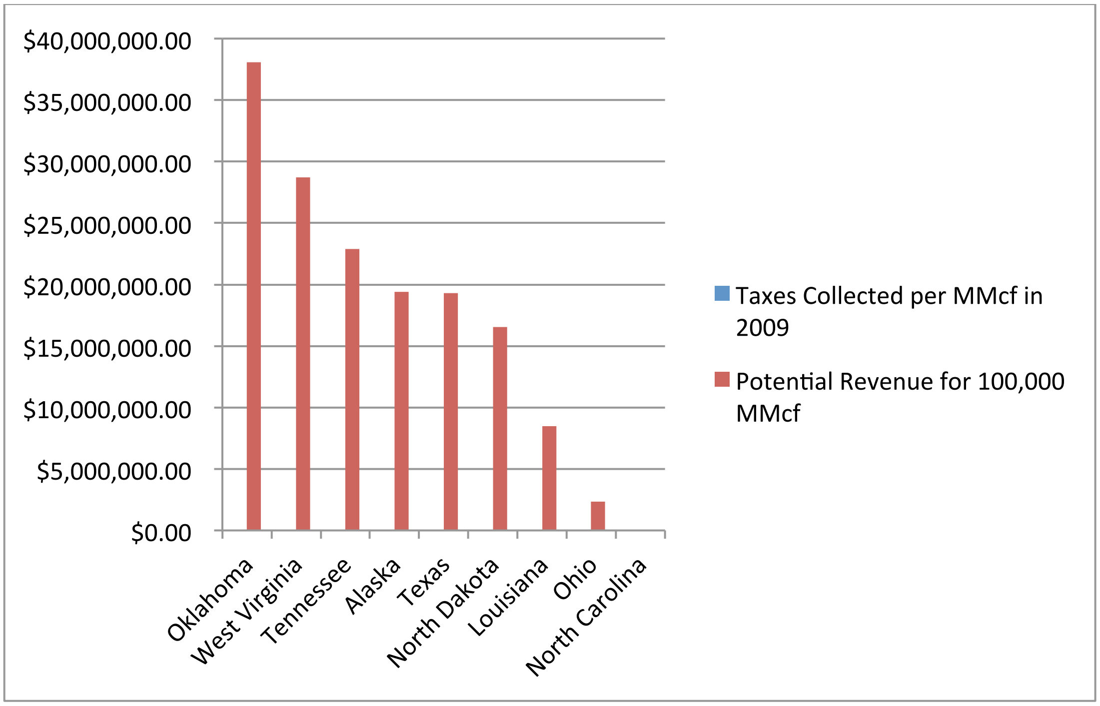
For the sake of comparison, Table 5-9 shows a hypothetical example of what North Carolina would collect if the Triassic Basins produced natural gas using the amount of taxes collected per MMcf found by the Marshall University study and shown in Table 5-8 above. A graphical representation of this estimate is shown in Figure 5-1.

Table 5-9. Estimated Revenues Based on Other States' Tax Collections

State Severance Tax Collection	Taxes Collected per MMcf in 2009	Potential Revenue for 100,000 MMcf	Potential Revenue for 1,000 MMcf
Oklahoma	$380.72	$38,072,000	$380,720
West Virginia	$287.21	$28,721,000	$287,210
Tennessee	$228.71	$22,871,000	$228,710
Alaska	$194.27	$19,427,000	$194,270
Texas	$193.25	$19,325,000	$193,250
North Dakota	$165.27	$16,526,821	$165,268
Louisiana	$84.74	$8,474,000	$84,740
Ohio	$23.30	$2,330,000	$23,300
North Carolina	N/A (existing severance tax rate used in calculation)	$50,000	$500

[343] Marshall University Center for Business and Economic Research. "Taxation of Natural Gas: A Comparative Analysis, Severance Tax Review." December 13, 2011. Retrieved March 5, 2012 from http://www.marshall.edu/cber/research/SeveranceTaxReviewFinal.pdf.

Figure 5-1. Estimated Revenues Using Other States' Tax Collections



L. Fees for permitting oil and gas exploration and production activities

Well permitting fees in North Carolina and other states

State fees for permits to drill an oil or gas well range from $0 to more than $3,000. The U.S. Bureau of Land Management charges a $6,500 fee to drill on federal land. That fee has been effective since 2009 (the previous fee was $4,000), and the money generated "constitutes a reimbursement to the U.S. Treasury for the estimated cost of processing new APDs".[344] Of the states researched for this report, Colorado, Maryland and New Mexico do not charge any fee. (Colorado statutes authorize the Oil and Gas Conservation Commission to charge a permit fee of up to $200,[345] but according to the Oil and Gas Conservation Commission's website, the current fee is $0.[346]) Wyoming charges a minimal $50. Louisiana, New York, Pennsylvania and Texas charge fees at a range of rates based on the depth of the wells to be drilled. Ohio charges

[344] Gorey, Tom. "BLM Will Collect $6,500 Processing Fee for Each New Oil and Gas Drilling Permit Application." November 4, 2009. U.S. Department of the Interior Bureau of Land Management. Retrieved March 5, 2012 from http://www.blm.gov/wo/st/en/info/newsroom/2009/november/NR_11_04_2009.html.
[345] Colorado Revised Statutes § 34-60-160(1)(f). Retrieved March 9, 2012 from http://www.michie.com/colorado/lpext.dll?f=templates&fn=main-h.htm&cp=.
[346] Colorado Oil and Gas Conservation Commission. "Fee Structure." Retrieved March 9, 2012 from http://cogcc.state.co.us/ (selected Rules from menu on lefthand side of page, then choose "Appendix III - Fee Structure").

a range of fees based on the population size of the town in which the well is drilled. Permit fees for a number of states are shown in Table 5-10 on the next page.[347]

[347] Alabama permit fee found at http://www.ogb.state.al.us/documents/forms/pdf/ogb01.pdf; Alaska permit fee found at http://dog.dnr.alaska.gov/Permitting/Documents/Application_Checklist_201111.pdf; Arkansas permit fee found at: http://www.aogc.state.ar.us/OnlineData/Forms/Rules%20and%20Regulations.pdf; BLM permit fee found at http://www.blm.gov/wo/st/en/info/newsroom/2009/november/NR_11_04_2009.html; Colorado permit fee found at http://cogcc.state.co.us/; Kentucky permit fee found at http://oilandgas.ky.gov/Documents/Oil%20and%20Gas%20Operators%20Manual.pdf; Louisiana permit fees found at http://dnr.louisiana.gov/assets/OC/exec_div/SWO_29_R_10_11_FEE_SCHEDULE.pdf; Maryland permit requirements found at http://www.dsd.state.md.us/comar/getfile.aspx?file=26.19.01.06.htm; Mississippi permit fee found at http://www.ogb.state.ms.us/docs/MSOGB_Rulebook_20111214.pdf; New Mexico permit fees obtained through personal communication with David Brooks, March 5, 2012; New York permit fee found at http://law.onecle.com/new-york/environmental-conservation/ENV023-1903_23-1903.html; Ohio permit fees found at http://codes.ohio.gov/orc/1509; Oklahoma permit fees found at http://www.okc.gov/pw/oilgas/pdf/DrillPermitForm.pdf; Pennsylvania fees found at http://www.pacode.com/secure/data/025/chapter78/chap78toc.html#78.19.; Tennessee permit fees found at http://tn.gov/environment/permits/oilgas.shtml; Texas permit fees found at http://info.sos.state.tx.us/pls/pub/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=3&rl=78; West Virginia fees found at http://www.legis.state.wv.us/wvcode/ChapterEntire.cfm?chap=22&art=6&section=2#06; and Wyoming fee found at http://wogcc.state.wy.us/downloads/HOW2FileAPD.pdf.

Table 5-10. Permit Fees for Drilling Natural Gas Wells in Selected States

State or Federal Agency	Permit Fee
Alabama	$300
Alaska	$250
Arkansas	$300
Bureau of Land Management	$6,500
Colorado	$0
Kentucky	$350
Louisiana	$126 (0-3,000 feet for 6 months) $631 (3,001-10,000 feet for 6 months) $1,264 (≥10,001 feet for 6 months) $252 (0-3,000 feet for 1 year) $1,262 (3,001-10,000 feet for 1 year) $2,528 (≥10,001 feet for 1 year)
Maryland	$0
Mississippi	$600
New Mexico	$0
New York	$190 - $3,800 or more
North Carolina	$3,000
Ohio	$500 (if well is in a township of 5,000-10,000 residents) $750 (if well is in a township of 10,000 - 15,000 residents) $1,000 (if well is in a township with ≥15,000 residents or a **for all permits,** an additional $5,000 if the permit requires mandatory pooling
Oklahoma	$2,200 + $550 processing fee
Pennsylvania	$900 to $3,000 or more, depending on depth (horizontal wells and wells drilled in Marcellus Shale)
Tennessee	$500
Texas	$200 (wells ≤2,000' deep) $225 (wells 2,000 - 4,000') $250 (wells 4,000 - 9,000') $300 (wells >9,000')
West Virginia	$650
Wyoming	$50

Well abandonment fees and other well fees in North Carolina and other states

North Carolina charges oil and gas operators a well abandonment fee in addition to the well drilling fee. Under current North Carolina law, an owner who intends to abandon a well must give DENR notice of the abandonment and pay a fee of $450.

Few other states appear to have a well abandonment fee. Tennessee has a temporary well abandonment fee of $100 per well per year. This fee is for "wells that are not producing but have not been plugged and closed out. The fee is due each year until the well is plugged."[348]

Arkansas requires all permit holders of liquid hydrocarbon wells and any Class II disposal or Class II enhanced recovery wells to pay annual fees as financial insurance. The amounts of the annual fees are shown in Table 5-11 below.

Table 5-11. Annual Fees for Well Permit Holders in Arkansas[349]

Number of Wells	Amount of Fee
1-5 permits or wells	$100/well
6-15 permits or wells	$750/operator
16-50 permits or wells	$1,250/operator
51-150 permits or wells	$2,000/operator
151-300 permits or wells	$3,000/operator
301 or more permits or wells	$4,000/operator

Louisiana also charges an annual fee, but this fee is based on the production of each well, as shown in Table 5-12 below.

Table 5-12. Annual Production Fees for Wells in Louisiana[350]

Tier	Annual Production (Barrel Oil Equivalent)	Fee per Well
Tier 1	0	$18
Tier 2	1 - 5,000	$98
Tier 3	5,001 - 15,000	$284
Tier 4	15,001 - 30,000	$467
Tier 5	30,0001 - 60,000	$742
Tier 6	60,001 - 110,000	$1,027
Tier 7	110,001 - 9,999,999	$1,217

[348] Tennessee Department of Environment & Conservation. "Permits." Retrieved March 9, 2012 from http://tn.gov/environment/permits/oilgas.shtml.

[349] Arkansas Oil and Gas Commission. *Arkansas Oil and Gas Commission General Rules and Regulations as of February 17, 2012*. 2012. Retrieved March 9, 2012 from http://www.aogc.state.ar.us/OnlineData/Forms/Rules%20and%20Regulations.pdf.

[350] Louisiana Office of Conservation. *Statewide Order No. 29-R-10/11*. November 19, 2010. Retrieved March 9, 2012 from http://dnr.louisiana.gov/assets/OC/exec_div/SWO_29_R_10_11_FEE_SCHEDULE.pdf.

In Maryland, operators of wells that have been permitted and drilled but not plugged and reported as plugged must pay an annual fee of $100 to the Emergency Plugging Fund of the Mississippi State Oil & Gas Board.[351]

Other environmental permitting fees in North Carolina

Anyone who intends to disturb land in North Carolina is required to apply for and obtain an erosion and sedimentation control plan from the N.C. Division of Land Resources (with the exception of some agricultural activities and those required to obtain a permit under the Mining Act of 1971). This requirement would apply to oil and gas operations as well. For applications for erosion and sedimentation control plans, the N.C. Division of Land Resources charges an application fee of $65 per acre of disturbed land. Additional environmental permitting requirements would vary depending on the specifics of each project.

M. Recommendations for funding state regulatory oversight

Appropriate level of severance taxes or royalty payments

North Carolina's current severance tax rate is lower than that of any other state that charges a severance tax. Further study is needed to determine an appropriate severance tax rate.

Recommendations for new or modified permit fees

Permit fees are collected once and intended to pay for the cost of reviewing applications for permission to drill. However, for an oil and gas program to effectively oversee oil and gas drilling sites, inspections must be conducted at various stages throughout the process, such as cementing and casing of the well, drilling the well and hydraulic fracturing. Inspections must also occur yearly or at some other regular interval. Ensuring oversight of drilling activity is critical to the protection of public health, groundwater resources, surface water resources and land resources. Severance taxes can be a volatile revenue source, increasing or decreasing based on the natural gas market. However, the need to inspect oil and gas sites exists whether or not the market is booming. Since program costs are annual and ongoing, DENR recommends that the General Assembly should authorize an annual fee to recover the costs of inspections and data collection, rather than depending on severance tax revenue to pay for this set of program costs.

N. Other recommended uses for oil and gas revenue

In other oil- and gas-producing states, revenues from oil and gas fees and taxes are used to support conservation initiatives, local governments impacted by the industry and for reclamation and remediation of lands impacted by oil and gas drilling. For instance, Colorado's severance tax revenue is divided between the Department of Natural Resources (DNR) and the Department of Local Affairs (DOLA). DNR's share of the revenue is used to provide "loans for

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[351] Mississippi Oil and Gas Board. *State Oil and Gas Board Statutes, Rules of Procedure, Statewide Rules and Regulations*. November 16, 2011. Retrieved March 9, 2012 from http://www.ogb.state.ms.us/docs/MSOGB_Rulebook_20111214.pdf.

state water projects administered by the Colorado Conservation Board,"[352] regulatory functions, species conservation, water efficiency grants and low-income energy assistance. The regulatory functions supported include the Oil and Gas Conservation Commission, the Colorado Geological Survey, the Division of Minerals and Geology and the Water Conservation Board. DOLA's share of the severance tax is distributed to local governments in two ways. Seventy percent of the revenue is used for loans and grants to local governments that are "socially or economically impacted by the mineral extraction industry." The remaining 30 percent is distributed directly to local governments based on the proportion of the mineral industry in each county.[353]

DENR recommends that severance taxes and program fees collected should fund:

1) the administration of the oil and gas program;
2) conservation initiatives, including land and water conservation and the improvement of water and wastewater infrastructure;
3) reclamation and remediation of lands adversely impacted by oil and gas exploration and production; and
4) costs incurred by local governments for infrastructure and public services as a result of industry activity.

Further study is needed to determine the distribution amounts for each of these needs.

[352] Colorado Legislative Council Staff. "Mineral Taxes." December 2010. Retrieved March 10, 2012 from http://www.colorado.gov/cs/Satellite?blobcol=urldata&blobheader=application%2Fpdf&blobkey=id&blobtable=MungoBlobs&blobwhere=1251672450913&ssbinary=true.
[353] Ibid.

Section 6 – Potential social impacts

A. Potential impacts on housing availability

Natural gas and oil development has had a major impact on the cost and availability of rental housing in states such as Pennsylvania and North Dakota. In areas with a short supply of workers trained in the field of natural gas and oil construction, companies must import crews from other states.[354] These workers, skilled in drilling, hydraulic fracturing or other specialized skills, typically seek rental housing within one hour of their worksites.[355]

Examples from other states

As drilling activity has increased in certain parts of the United States, rural areas and small towns have, in some cases, been overwhelmed by the demand for worker housing. In some parts of northern Pennsylvania, drilling in the Marcellus has led to shortages in affordable housing. Townships in several Pennsylvania counties (such as Bradford, Lycoming and Tioga counties) have seen spikes in housing costs, as rates for hotel rooms and rental units increase in response to greater housing demand.[356]

The impact of gas production on housing costs and availability likely depends on three key factors: 1) the speed and scale of industry growth in a given community; 2) the existing housing capacity of a community before drilling begins; and 3) the industry's need to import workers skilled in gas production activities. For example, communities with faster industry growth tend to experience greater increases in housing costs, especially if those communities lack adequate housing stock to accommodate an influx of new workers.[357]

Examples of housing shortages associated with oil and gas development have also come from the American Mountain West. In Colorado, Mesa and Garfield counties experienced a spike in housing costs as energy companies developed the oil and gas fields of the Western Slope.[358] Grand Junction, the region's largest city at 58,566 people, has experienced steady increases in the cost of living.[359]

Other examples include Sublette County, Wyo., which has seen a decrease in affordable housing since its nearby oilfields have grown.[360] In South Texas, the Eagle Ford shale play has revitalized small towns, and driven up housing prices.[361] These communities, largely rural in character and lacking adequate housing supply, have struggled to maintain affordable living

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[354] Andree interview, 2011; Brasier, 2011; Jacquet, 2009; Patton et al, 2011.
[355] Brasier interview, 2011.
[356] Blevins interview, 2012; Daley, 2011; Junkins, 2011; Laughner, 2012; Maroney, 2011; Mullin and Lonergan, 2010; Reuther, 2011; Stender, 2011; Turner, 2011; Williamson and Kolb, 2011.
[357] Blevins interview, 2012; Williamson and Kolb, 2011.
[358] Headwaters, 2008.
[359] Bullen, 2009.
[360] Jacquet, 2007.
[361] Hiller, 2011; Hiller and Vaughan, 2011; Mildenberg, 2011.

options. A 2011 environmental impact statement prepared by the state of New York also indicates that drilling activity would lead, at least temporarily, to shortages in rental housing.[362]

One extreme example of housing shortages comes from North Dakota's Bakken shale oil region. Housing shortages in and around Williston, the area's commercial hub, have led to residents struggling to afford rising rental rates, workers sleeping in cars and hotels booked solid for years in advance.[363]

Not all oil and gas development leads to housing shortages, however. Production in the Barnett shale region of Texas, centered in and around the Dallas-Fort Worth metropolitan area, does not appear to have greatly impacted the availability or affordability of rental housing. The Barnett shale region differs from areas that have experienced housing shortages and cost increases in two respects: natural gas development makes up a relatively small portion of the region's economic activity, and most of the natural gas workforce could be supplied locally.

In the Marcellus region, areas that have experienced modest amounts of drilling have not seen rising housing costs. Counties such as Armstrong and Butler in Pennsylvania's Southwest, where gas production pales in comparison to neighboring Washington County, report only a modest increase in hotel occupancy and room rates.[364]

Distributional impacts

The effects of increased rental housing costs are felt in varying degrees by different social groups in any impacted community. Rental property owners, naturally, enjoy increased return on their property investments. Landlords in some gas and oil-impacted communities have raised their monthly rates, in some cases displacing former tenants.[365]

Hotel owners and proprietors, likewise, benefit from increased occupancy rates. These businesses are often the first to benefit from oil and gas activity, as industry representatives and "land men" acquire leases and prepare for development. For example, preparations for oil and gas development in eastern Ohio's newly discovered Utica shale has led to a spike in hotel occupancy.[366]

Local residents in rental housing, on the other hand, can experience the negative impacts of increased housing costs resulting from natural gas development. In some areas of Pennsylvania, senior citizens, people with disabilities and other individuals living on a low or fixed income have been priced out of their homes. Some of these individuals and families have been forced to "double" or "triple-up" with other families; move to neighboring counties; relocate to mobile homes or local campgrounds; and in some cases face homelessness.[367]

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[362] NYSDEC, 2011.
[363] Ellis, 2011; North Dakota Housing Finance Agency, 2011; Oldham, 2012; Shactman, 2012; Zarling, 2012.
[364] Coonley interview, 2011; Pennsylvania Department of Environmental Protection, 2012; Pinkerton interview, 2011; Pozzuto interview, 2011.
[365] Blevins interview, 2012; Daley, 2011; Hiller, 2011; Maroney, 2011; Stender, 2011; Smith-Heavenrich, 2011.
[366] Henkel, 2011; Pritchard, 2011.
[367] Blevins interview, 2012; Patton et al, 2011; Reeger, 2012; Skillings, 2010; Williamson and Kolb, 2011.

In a few communities around the United States, housing has simply become unavailable. Although oil and gas companies in North Dakota, Pennsylvania, and Wyoming have sought to alleviate these shortages with temporary housing units (sometimes called “man camps”), demand continues to outstrip supply in some communities.[368]

Rental housing stock and affordability in potentially affected North Carolina counties

Counties with large populations of low- or fixed-income renters could be the most impacted from increased costs of housing if extensive shale gas development were to take place in North Carolina. Individuals or families paying above 30 percent of their monthly income on housing would be particularly susceptible. Figure 6-1 and Figure 6-2 show some relevant characteristics:

Figure 6-1. Demographics and Economics of Housing in Deep River Basin Counties

County	Population over Age 65, 2010	Households below Poverty Level, 2005-09	Unemployment Rate, Dec. 2011	Spending >30% of Income on Housing, 2005-09
Anson	14.3%	24.1%	12.1%	53.6%
Chatham	18.3%	11.0%	8.4%	48.6%
Durham	9.8%	16.4%	7.5%	47.8%
Granville	12.4%	14.8%	9.8%	43.5%
Lee	13.7%	14.5%	12.3%	44.6%
Montgomery	15.7%	21.3%	12.0%	43.1%
Moore	22.6%	13.3%	9.0%	46.6%
Orange	9.6%	16.9%	6.1%	59.1%
Richmond	14.3%	30.0%	13.0%	42.8%
Union	9.7%	10.9%	8.9%	48.5%
Wake	8.5%	10.2%	7.7%	45.3%
N.C. average	14.3%	16.2%	9.8%	47.9%

Source: U.S. Census Bureau, U.S. Bureau of Labor Statistics

Figure 6-2. Demographics and Economics of Housing in the Dan River Basin Counties

County	Population over Age 65, 2010	Households below Poverty Level, 2005-09	Unemployment Rate, Oct. 2011	Spending >30% of Income on Housing, 2005-09
Davie	16.6%	11.7%	10.4%	43.2%
Rockingham	16.2%	14.9%	11.4%	40.6%
Stokes	16.0%	11.2%	8.4%	40.9%
Yadkin	16.3%	13.4%	9.0%	42.1%
N.C. average	14.3%	16.2%	9.8%	47.9%

Source: U.S. Census Bureau, U.S. Bureau of Labor Statistics

[368] Blevins interview, 2012; Konigsberg, 2011; Press and Sun Bulletin, 2010; Shactman, 2012.

Each column in the above tables indicates a potential risk factor for affordable housing shortages in the event of a surge in demand for rental housing. Retirees, often living on fixed incomes, could struggle more than the working-age population to adjust to higher housing costs. Similarly, households with incomes below the poverty line could struggle to afford any additional housing costs.

A high countywide unemployment rate would be another indicator that the local population may be negatively affected by increased living expenses. On the other hand, natural gas exploration may increase economic activity, lowering unemployment rates and leading to a population more capable of affording increased housing costs.[369]

Figure 6-3. Housing Characteristics of Counties in the Deep River Basin, 2005-2009

County	Homeownership Rate	Rental Vacancy Rate	Median Rent (dollars per month)
Anson	69.7%	10.6%	585
Chatham	78.4%	10.0%	728
Durham	55.9%	9.8%	786
Granville	75.3%	3.7%	666
Lee	71.6%	7.7%	611
Montgomery	75.3%	12.6%	492
Moore	76.6%	12.6%	642
Orange	59.5%	10.2%	795
Richmond	70.3%	12.4%	487
Union	79.9%	5.5%	769
Wake	66.6%	8.7%	826
N.C. average	68.1%	9.7%	702

Source: U.S. Census Bureau American Communities Survey, 2005-2009.

Figure 6-4. Housing Characteristics of Counties in the Dan River Basin, 2005-2009

County	Homeownership Rate	Rental Vacancy Rate	Median Rent (Dollars per Month)
Davie	83.8%	9.4%	694
Rockingham	71.4%	11.7%	549
Stokes	81.2%	6.9%	533
Yadkin	78.0%	10.5%	512
N.C. average	68.1%	9.7%	702

Source: U.S. Census Bureau American Communities Survey, 2005-2009.

Again, the columns shown above indicate potential risk factors for affordable housing shortages in the event of a surge in demand for rental housing. Homeownership rates are significant because homeowners would likely experience less impact from increased rental costs. Indeed,

[369] Blevins interview, 2012; Considine, 2011; Headwaters, 2011; Hefley, 2011; IHS Global Insight, 2011; Perryman, 2011.

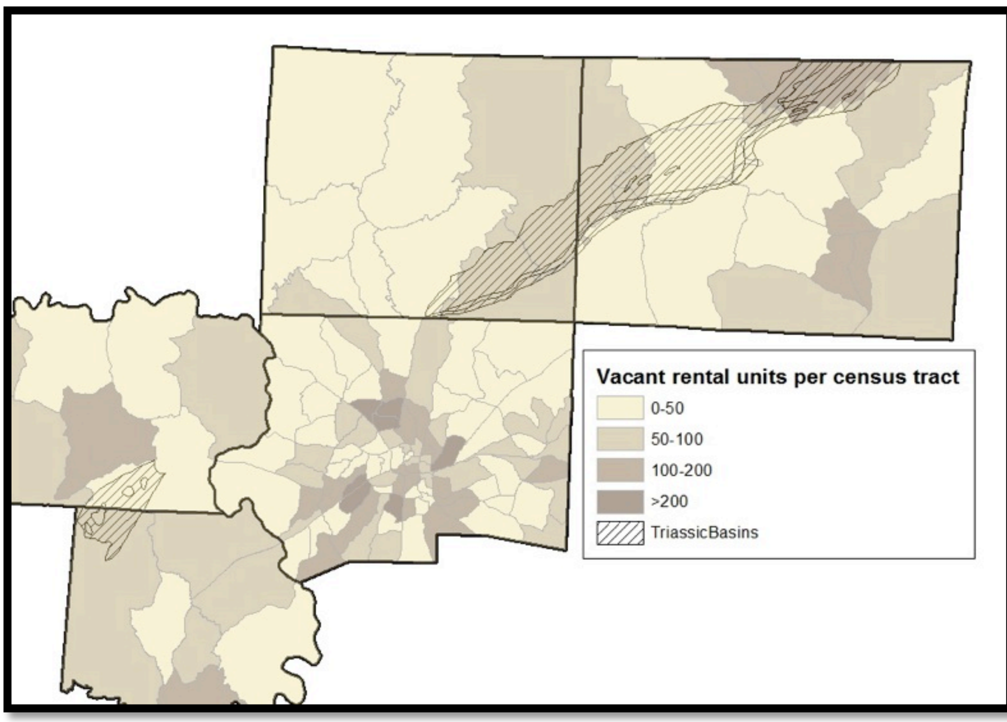
homeowners in some gas-heavy areas around the United States have supplemented their income by renting out spare rooms to oil and gas industry workers.[370] On the other hand, residents of counties with low homeownership rates (such as Durham or Orange counties) may be more heavily impacted by increased rental costs.

Low vacancy rates indicate a tight supply of additional rental housing units. If significant gas development occurred, a shortage of affordable housing could be more likely in counties such as Granville, Lee, Stokes or Union Counties, which have relatively low rental vacancy rates. Finally, median rental rates give perspective on how many dollars per month households spend on rental housing.

Estimated vacant rental units in the Dan and Deep River basins

The images below depict the estimated number of rental units available in each census tract of potentially impacted North Carolina counties. If these 2010 estimates closely resemble the amount of currently available rental housing, each region should be able to accommodate thousands of additional tenants.

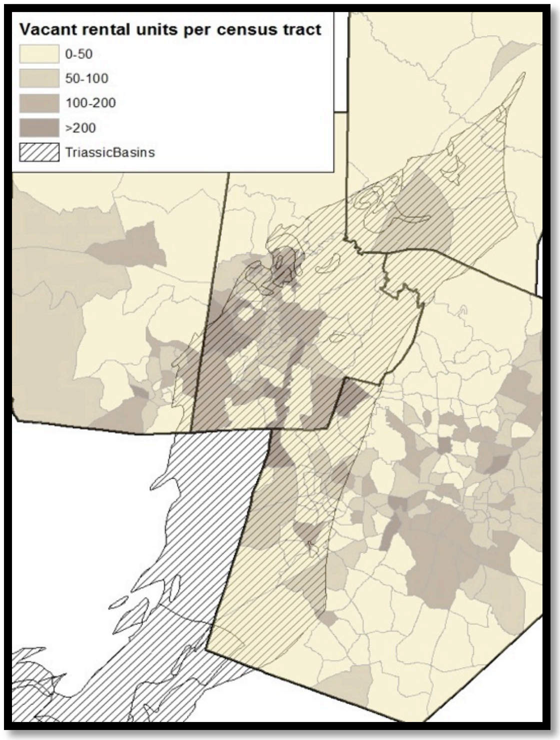
Figure 6-5. Estimated Vacant Rental Units in Dan River Basin, 2010



Source: U.S. Census Bureau, NCOneMap geospatial data, N.C. Geological Survey

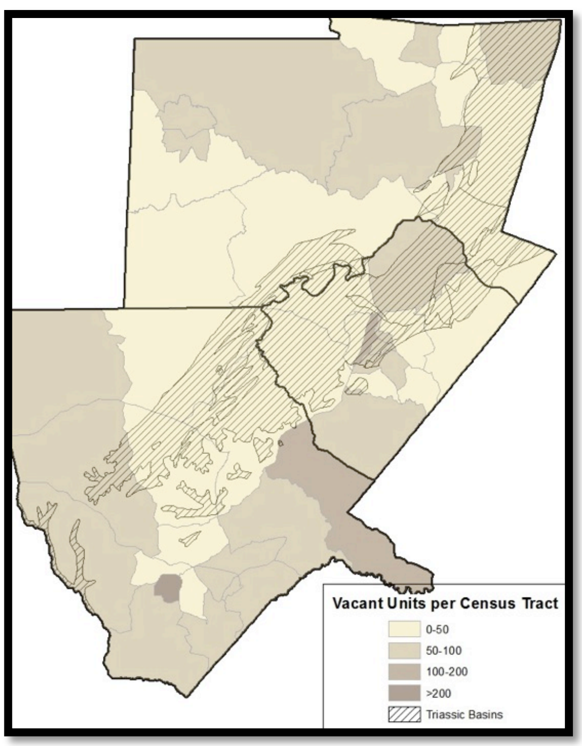
[370] A web search for rental housing in active drilling areas in Pennsylvania, Texas, North Dakota and Colorado turns up many such offers from local homeowners.

Figure 6-6. Estimated Vacant Rental Units in Durham Sub-basin, 2010



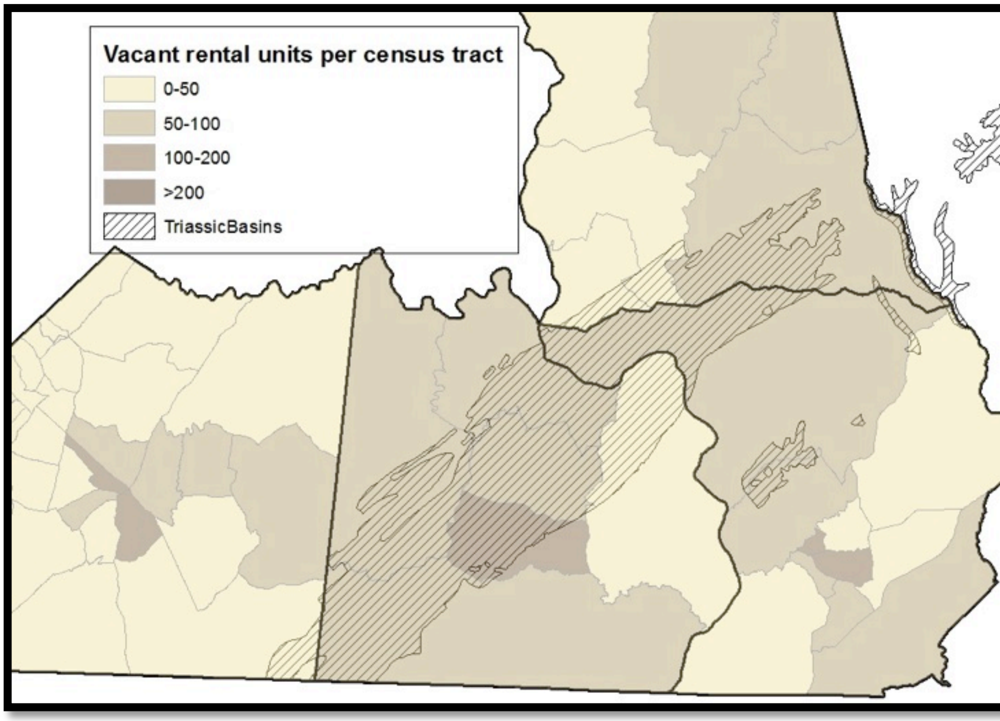
Source: U.S. Census Bureau, NCOneMap geospatial data, N.C. Geological Survey

Figure 6-7. Estimated Vacant Rental Units in Sanford Sub-basin, 2010



Source: U.S. Census Bureau, NCOneMap geospatial data, N.C. Geological Survey

Figure 6-8. Estimated Vacant Rental Units in Wadesboro Sub-basin, 2010



Source: U.S. Census Bureau, NCOneMap geospatial data, N.C. Geological Survey

Housing options

Construction of well pads, drilling, hydraulic fracturing and completion of wells requires significantly greater numbers of workers than maintenance and monitoring of those wells.[371] Any spike in demand for housing related to the natural gas industry may not be sustained in the long term. Construction of permanent housing for workers during a spike in housing demand, such as new hotels or motels, could lead to an oversupply once drilling activity has declined.

Mobile housing units could be one option for housing out-of-state workers. Demand for mobile homes, trailers and campground space has surged in parts of Pennsylvania, and a similar effect could occur in North Carolina.[372] If housing shortages become a major issue, natural gas companies may construct "man camps" in areas close to drilling locations.

Experience from Pennsylvania indicates that natural gas workers are typically willing to commute up to an hour each way to work on a well site.[373] Because of the large number of metropolitan areas within an hour of North Carolina's Durham and Sanford sub-basins, workers may be expected to commute from cities including Raleigh, Durham, Chapel Hill or Fayetteville. If drilling occurs in the Dan River shale region, workers may commute from Greensboro, Winston-Salem or other proximate cities. The Wadesboro sub-basin, while within an hour of

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[371] Considine, 2011; IHS Global Insight, 2011; Marcellus Shale Education and Training Center, 2010, NYSDEC, 2011.
[372] Andree interview, 2011; Brasier interview, 2012; Coonley interview 2011; Mullin and Lonergan, 2010; Williamson and Kolb, 2011.
[373] Brasier interview, 2011.

the greater Charlotte metropolitan area, is more isolated, which may create greater risk for housing shortages.

Figure 6-9. Commute Times (in minutes) to North Carolina Shale Regions

From:	**To**: Sanford (Sanford sub-basin)
Cary	43
Chapel Hill	50
Durham	61
Fayetteville	55
Pinehurst	39
Pittsboro	26
Raleigh	47

From:	**To**: Durham (Durham sub-basin)
Cary	27
Chapel Hill	24
Greensboro	65
Pittsboro	46
Raleigh	32
Sanford	61

From:	**To:** Madison (Dan River basin)
Burlington	64
Danville, Va.	56
Eden	23
Greensboro	40
Reidsville	30
Winston-Salem	43

From:	**To**: Wadesboro (Wadesboro sub-basin)
Asheboro	74
Charlotte	65
Fayetteville	90
Lumberton	76

Source: Google directions

Note: All times were computed using city centers as start and end points

B. Potential impacts on property values

Natural gas drilling has the potential to impact property values in different ways for individual property owners. Landowners who have economically recoverable gas resources and control their own mineral rights may benefit from increased property values. Those who do not own the mineral rights under their property, however, are unlikely to see such increases.

Proximity to natural gas production, transmission, and storage facilities also could impact property values, although economists and researchers have not reached consensus on the direction of the impact or its extent. In any case, experiences in other states or countries will not necessarily predict the impacts of these facilities on North Carolina property owners.

Drilling sites

Property owners who control the mineral rights to economically recoverable gas resources under their land may see substantial increases in property values. In Pennsylvania's Marcellus region, property values in gas-rich areas have risen significantly in the past several years.[374] An economic analysis prepared for Broome County in New York State, which sits atop large Marcellus shale deposits, predicted that if 2,000 wells were drilled in the county, property tax revenue was likely to increase by $119 million.[375] This same analysis claimed that the taxable value of oil and gas properties in Texas' Barnett shale region increased from $341 million to $5.9 billion, a 1,730 percent increase, from 2000-2005.[376]

These increases in property value and the associated tax revenues result from two key factors. First, property owners often receive bonuses upon signing an oil and gas lease agreement. These agreements can range anywhere from $5 per acre to $20,000 per acre.[377] On properties where lease agreements have not been signed, potential buyers may factor expected bonus payment into the value of the property. Second, mineral owners receive royalties on income from gas production, typically earning 12.5 percent to 20 percent of the gas revenue generated at their wellhead.

Not all researchers agree on increased property values associated with natural gas drilling. A study commissioned by the town of Flower Mound, Texas, in the Barnett shale region, found that properties valued above $250,000 experience a 3 percent to 14 percent decrease in value if the property is within sight of a drilling pad. The same study also found that if the drilling site is visually obscured, there was no impact on property values.[378] These decreases in property value were attributed to quality of life factors such as noise and visual impacts.

Another study examining coalbed methane mining operations in southwest Colorado in the 1990s concluded that properties where drilling occurred experienced significant decreases in value. The net impact of wells on these properties was estimated to be a 22 percent decrease in

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[374] Kelsey et al., 2012; Laughner, 2012; Patton et al., 2010.
[375] This report overestimated natural gas prices based on 2009 forecasts by the U.S. Energy Information Administration. Given current price trends, tax revenue would be significantly lower.
[376] Texas Comptroller of Public Accounts via Weinstein and Clower, 2009.
[377] Kallenberg, 2011; Treakle, 2011.
[378] Integra, 2010.

value. Conversely, the study found that properties within 550 feet of well development, but where development did not occur on that property, experienced a net increase in value.[379] This increase was attributed to the belief that drilling on a property was unlikely to occur if a well had been drilled "next door."

Natural gas pipelines

Pipelines are an essential tool for transporting natural gas from the wellhead to a distribution network. Currently, North Carolina has 2,848 miles of natural gas pipeline in place, consisting mostly of low-volume distribution lines.[380] A variety of studies conducted by researchers, industry and trade associations have sought to determine whether natural gas pipelines impact residential property values. For the most part, these studies find that natural gas pipelines do not significantly impact the value of nearby homes. However, some press reports and anecdotes report otherwise.

Two studies published in the journal of the International Right of Way Association, one conducted in the southwest United States and the other in Connecticut, find that natural gas pipelines do not impact property values.[381] Two studies from 2008, commissioned by pipeline developers and prepared by environmental consultancies in Oregon, also found no significant impact on property values from pipeline development.[382] Another study, prepared for the Interstate Natural Gas Association of America Foundation by a Texas-based consultancy in 2001, found no impacts on property values from pipeline developments in Connecticut, Oregon and two regions of Texas.[383] It is conceivable that potential property buyers would perceive proximity to a natural gas pipeline as a risk. However, research indicates that, in the absence of a high-profile accident (such as a pipeline rupture or major spill), fuel pipelines do not impact property values.[384]

Still, anecdotal evidence of pipeline construction resulting in lower property values does exist. In Texas, a recent appellate court decision upheld a jury award of $600,000 to a family whose ranch was perceived to have been negatively impacted by the presence of a natural gas pipeline.[385] In addition, some advocacy groups claim that pipeline construction will reduce property values in their communities.[386]

Natural gas processing facilities

Natural gas processing facilities, including compressor stations and "sour gas" facilities, may have some impact on nearby property values. Currently, North Carolina is home to five natural gas compressor stations.[387] A small amount of academic research, coupled with a variety of

[379] BBC Consulting, 2001.
[380] Source: U.S. Energy Information Administration, 2012.
[381] Diskin et al., 2011; Kinnard et al., 1994.
[382] Fruits, 2008; Palmer, 2008.
[383] Allen et al, 2001.
[384] Hansen et al., 2006.
[385] Gilbert, 2012.
[386] Ga, 2012.
[387] Source: U.S. Energy Information Administration, 2012.

anecdotal evidence, suggests that these facilities may have a negative impact on the value of nearby properties. A 2005 study in Alberta, Canada, indicated that rural properties within four kilometers (roughly 2.5 miles) of oil or "sour gas" processing facilities negatively impacted their property values.[388] However, two studies conducted in Alberta in1988 and 1991, both commissioned by Shell of Canada, showed that sour gas facilities did not impact residential property values.[389]

Anecdotal evidence from several parts of the United States indicates that some of these facilities can impact quality of life of nearby residents, depress property values and in some cases cause individuals to leave the community. A number of residents – including Mayor Calvin Tillman – have moved out of DISH, Texas, citing health problems caused by air pollution attributed to several natural gas compressor stations in the town.[390] Reports from Decatur, Texas (in the Barnett shale region) also indicate health problems and declining property values associated with natural gas processing facilities.[391] While a wide variety of news media have reported on health problems and loss in property values, none of these negative impacts have been definitively linked to a specific natural gas processing facility.[392] Significant uncertainty remains as to whether processing facilities or compressor stations are responsible for the reported health problems.

Valuation and mortgage issues

Evaluating the worth of a property with shale gas resources presents a potential dilemma for some banks and other lending institutions. If a property has economically recoverable gas resources, that property is likely to increase in value; however, banks and other potential lenders may not be able to accurately assess the monetary value of the resource. Lacking an adequate picture of a property's true value, banks may be hesitant to extend mortgages or refinancing packages to landowners. Lenders may be concerned that they are either undervaluing or overvaluing a property, since gas development and resulting royalty payments are not uniform across all leased lands. In North Carolina, where minimal oil and gas development has occurred, lenders would find it difficult to make comparisons between what would appear to be comparable properties.

Reports from New York State's Marcellus region suggests that confusion exists surrounding how to value properties with shale gas potential. In some New York communities, landowners have reported difficulty in finding lenders willing to extend credit on leased properties.[393] Potentially increasing confusion among banks, the Congressional Research Service released a letter in September 2011 indicating that Fannie Mae and Freddie Mac do not consider properties with oil or gas leases to fall into their "conforming loan" category.[394] The loans would be considered

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[388] Boxall et al., 2005.
[389] Deloitte et al, 1988; Lore et al., 1991.
[390] Zelman, 2011.
[391] Heinkel-Wolfe, 2010.
[392] Bateman, 2010; Burnett, 2009; Heinkel-Wofle, 2010; Lustgarten and Kusnetz, 2011; Wheeler, 2012; Zelman, 2011; Zook, 2010.
[393] Lucas, 2011; Tavernise, 2011; Urbina, 2011.
[394] Carpenter, 2011.

"non-conforming," since appraisers may not be able to properly value the worth of subsurface minerals, and may find it difficult to find comparable properties in the area. Typically, loans that are not "conforming" are more risky for lenders, as they are unable to re-sell the mortgages to Fannie Mae and Freddie Mac.[395] As a result, banks may be reluctant to extend credit for mortgages or refinancing packages to properties where oil or gas leases have been signed.

If gas leasing activity begins to grow quickly, homeowners who otherwise may sell could be inclined to "sit" on their properties in hopes of obtaining increased returns on their mineral estates. Anecdotal evidence from northeast Pennsylvania and Ohio suggest this type of activity may be inhibiting the property market in some communities.[396]

Property valuation questions may be further complicated by uncertainty over ownership of the mineral rights. In Lee County, N.C., gas leasing has led to confusion over ownership of some mineral estates. Due to old systems of recordkeeping, it may prove difficult for some owners to establish title to their mineral estates.[397]

Analysis of data on property values

For this study, DENR looked at average (median) list prices of properties in several regions where natural gas development has significantly increased over the past three years. Zillow real estate price tracking software was used to find the list price for real property in the regions studied. Note that "list price" refers to the initial price set by the seller and not the ultimate sale price. Data from the past three years suggest that property values have increased in some, but not all, regions where significant new gas drilling operations have begun.

In Colorado, property list prices declined across Colorado by six percent between 2009 and 2012. In the state's top 10 gas-producing counties, however, property list prices declined by 19 percent. Colorado is the only region in this analysis where list values in the top gas-producing counties distinctly under-performed the rest of the region. The reasons for this finding are unclear.

In Oklahoma and Pennsylvania, listed property values in the top 10 gas-producing counties outperformed values in other counties by a wide margin. In Oklahoma, listed property values statewide declined by seven percent. In the top 10 gas-producing counties, listed values increased by seven percent, outperforming the rest of the state by 14 percent. In Pennsylvania, properties in the top 10 gas-producing counties showed an 18 percent increase from 2009-2012, compared with a 21 percent decline in the rest of the state. This represents a 39 percent difference.

In Texas' two major shale gas fields, the Barnett and Eagle Ford plays, property values in the top 10 gas-producing counties showed little difference from their regional counterparts.[398]

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[395] U.S. Dept. of Treasury, Feb. 2011.
[396] Blevins interview, 2012; Pompili, 2012.
[397] Murawski, Nov. 2011; Treakle, 2011 presentation.
[398] These two regions were analyzed distinctly from the entire state, given Texas' large size and wide variety of gas and oil producing areas.

Table 6-1. Change in Average Property Values, 2009-2012

Region[399]	Average change, entire region	Average change, Top 10 Gas Producing Counties
CO entire state	-6%	-19%
OK entire state	-7%	+7%
PA entire state	-21%	+18%
TX Barnett	-5%	-6%
TX Eagle Ford	0%	+1%

Data Source: Zillow.com real estate data tool.

Limitations of data analysis

This analysis provides a useful starting point for future research, but does not support a causal relationship between shale gas production and property values. A wide variety of factors have not been controlled for in this analysis. Some of these limitations are described below:

- Due to time and data limitations, DENR analyzed list prices instead of sale prices. As a result, we do not know whether these values held up in the final sale. Homeowners in gas regions of Oklahoma or Pennsylvania may have listed their land at values that the market would not accept.
- This is not a statistical analysis. The top 10 gas-producing counties in each of these regions may share common characteristics that are not controlled for in this analysis, including demographic, economic, social and quality of life factors. Simply put, a variety of local factors may be responsible for the differences in price between top gas-producing counties and the region as a whole.
- The data source, Zillow, is relatively new and untested. Zillow real estate price tracking software may not capture every property in a given market and therefore may distort the actual list prices in relevant regions.
- Three years is a relatively short time period. Changes in price over more years would give a better picture of how property values in each region would be impacted.
- The past five years have been a volatile time in the housing market around the United States. As the region averages show, many communities have experienced significant declines in property values. Impacts may differ during more stable periods in the national or regional housing markets.

Counties included in analysis of property values

Colorado: All counties.

Oklahoma: All counties.

Pennsylvania: All counties.

[399] See below for counties included in Texas regions.

Texas Barnett Region: Archer, Bosque, Clay, Comanche, Cooke, Coryell, Dallas, Denton, Eastland, Ellis, Erath, Hamilton, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Shackleford, Somervell, Stephens, Tarrant, Wise Counties.

Texas Eagle Ford Region: Atascosa, Bee, Brazos, Burleson, DeWitt, Dimmit, Edwards, Fayette, Frio, Gonzales, Grimes, Houston, Karnes, La Salle, Lavaca, Lee, Leon, Live Oak, Maverick, McMullen, Milam, Webb, Wilson, Wood, Zavala Counties.

C. Potential impacts on demand for social services

As with many other potential social impacts, the demand on social service providers will likely depend on the scale of economic and population growth in the affected area. In North Carolina, a small population influx resulting from the oil and gas industry would likely have a small impact on social service demands; rapid industry growth would likely lead to more demand for services.

Potential for decreased demand on social services

Shale gas development has brought increased employment, higher incomes and new wealth to several regions of the country. The influx of economic activity from gas industry employees has also benefitted businesses in the shale regions that are not directly related to gas production. This increased economic activity has led to increased income and wealth for some, but not all, local residents.

When a region experiences gains in wealth for any reason, the demand for social services tends to drop. Those who do not gain from an economic boom, however, can experience negative impacts due to inflation of local housing costs, scarcity of low and moderate income housing, and overtaxed medical and mental health services. In areas with rapid population growth, the growth may result in overcrowded public schools. These impacts have been reported in a variety of American shale regions, but are not inevitable in North Carolina if shale gas development occurs.

Housing assistance

Sections 6.A and 6.B describe some of the potential impacts on local housing markets related to natural gas development. Greater demand for rental units can reduce the availability and affordability of rental housing. Although increased occupancy rates for rental units and hotels and upward pressure on rental rates may benefit local landowners, these same changes can negatively impact individuals on low or fixed incomes.

In northeastern Pennsylvania, increased rates of homelessness have been associated with increased housing costs in regions with heavy shale gas development.[400] These problems were exacerbated in Pennsylvania by severe flooding in the summer of 2001.[401] In North Dakota's Bakken region, industry workers and long-time residents have struggled to find affordable

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[400] Blevins interview, 2012; Mocarsky, 2011; Maroney, 2011; Mullin and Lonergan, 2010; Reeger, 2010; Skillings, 2010; Turner, 2010.

[401] Ibid.

housing options.[402] In South Texas' Eagle Ford region, small towns have also experienced a surge in demand for housing.[403]

These types of shortages can increase demand for local, state, and federal housing assistance programs. The county human services director for Bradford County, Pa., indicates that the surge in population and resulting increase in rental rates there have led to a "huge impact" on county services for the homeless.[404]

Not all communities where shale gas drilling takes place experience these impacts, however. Armstrong and Butler counties, in southwestern Pennsylvania, have seen a modest amount of new gas drilling without any major impacts on rental affordability.[405] These two counties have experienced modest growth in hotel occupancy rates, which local officials attribute in part to shale gas drilling.[406] Both Armstrong and Butler counties have an adequate supply of affordable housing, which may lessen the likelihood of a housing shortage.[407]

Traffic and policing

Increased traffic is a common occurrence in regions with new oil or gas drilling operations. Heavy and light-duty truck trips required for well pad construction, drilling, fracturing and completion number in the thousands for an individual well.[408] Significant increases in traffic may lead to additional motor vehicle crashes or increased demand for traffic control. Both place additional demand on police resources.

Transportation of liquids associated with hydraulic fracturing may also lead to additional policing requirements. Large trucks transport fresh water, produced water and liquid chemicals required for the drilling or fracturing process to and from the drill sites. Given the volume and nature of the liquids being transported, accident response can be both more complex and more time-consuming than a typical one or two-car accident. In Pennsylvania, spills from trucks transporting chemicals or produced water, along with an increase in accidents involving large trucks have increased demands on local police.[409] Any spills of hazardous chemicals require labor- and time-intensive responses from law enforcement and environmental agencies.

Finally, additional policing may be required if gas drilling projects are accompanied by any increase in crime rates. Section 6.C, Traffic and policing, documents cases of increased crime in heavily drilled regions. Such increases in crime do not always accompany oil and gas production and it is not clear how, if at all, oil and gas activity contributes to regional changes in crime rates. Still, the anecdotes and the statistical analysis described in Section 6.C, Traffic and policing, indicate that additional policing may be required to respond to changes in crime rates.

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[402] Ellis, 2011; North Dakota Housing Finance Agency, 2011; Oldham, 2012; Shactman, 2012; Zarling, 2012.
[403] Hiller, 2011; Hiller and Vaughan, 2011; Mildenberg, 2011.
[404] Blevins interview, 2012.
[405] Andree interview, 2011; Coonley interview, 2011; Pozzuto interview, 2011; Raybuck interview, 2011.
[406] Ibid.
[407] Ibid.
[408] NYSDEC, 2011.
[409] Associated Press, Dec. 2011; Blevins interview, 2012; Crompton, 2011; Detrow, Nov. 2011.

Emergency services

Over the past several years, requirements for emergency services have increased in some heavy oil and gas drilling regions. In regions unaccustomed to oil and gas activity, the specialized nature of the response required for spills, explosions or fires related to the industry may necessitate new equipment, training and staff.

In Pennsylvania and New York's Marcellus region, local police and fire crews have undergone additional training in responding to emergencies related to natural gas drilling.[410] Traffic accidents or well pad incidents involving natural gas-related chemicals or produced water may also require specialized response units.[411] In North Dakota's Bakken region, local officials cite the booming shale oil industry as the primary cause of a significant recent increase in ambulance calls, largely resulting from oilfield injuries and accidents involving large trucks.[412]

In rural areas where volunteer fire and rescue agencies handle most emergency responses, these additional demands may be particularly difficult to manage.

If natural gas extraction and production occurs in North Carolina, we should ensure that state agencies, local first responders and industry are prepared to respond to a well blowout, chemical spill or other emergency. We recommend that oil and gas operators be required to develop an emergency response plan; state criteria for an acceptable plan should include a requirement that a wild-well qualified person be on the well pad at all times and 911 addressing of all well locations. If shale gas development occurs in North Carolina, local governments will require additional funds to train their local emergency services providers. These providers will need training in responding to a variety of potential emergencies that could occur as a result of large truck accidents, hazardous materials truck accidents and accidents on drilling sites.

We also recommend that the General Assembly encourage the Department of Labor to review its readiness to inspect drilling sites and appropriately enforce the OSHA standards for this industry to prevent worker injuries or death.

Schools

Economic activity that leads to population growth has the potential to increase demand for schooling. Workers in the oil and gas industry may be less likely to bring their families to the regions where they work than employees of other, less mobile industries.[413] Nonetheless, fast-growing energy "boomtowns" can lead to strong growth in the local student population.[414]

Some U.S. regions with major, long-term shale oil or gas resources have reported increased demand for educational services. North Dakota's Bakken region has experienced some of the

[410] Detrow, Nov. 2011; WICZ,. 2011.
[411] Associated Press, Dec. 2011; Crompton, 2011; Detrow, Nov. 2011; Hamill and Buynovsky, 2011.
[412] Brissenden, 2012; Oldham, 2012; Springer, 2011.
[413] The "boomtown" scenario outlined in section 6 B 5 describes the often-transitory nature of oil and gas drilling crews. Andree interview 2011; Brasier interview, 2012; Christopherson and Richtor, 2011; Ondracek and Witwer 2011.
[414] Jacquet, 2009.

fastest population growth from gas development in recent years and has strained to prevent school overcrowding.[415] Billings, Mont., which has increasingly supplied workers for companies operating in the Bakken region, is also expecting a surge in students.[416] In northeastern Pennsylvania, schools have also seen an influx of new students from gas industry workers.[417]

Other social services

Anecdotal evidence and research from past decades indicate that some other social services may see increased demand. In Bradford County, Pennsylvania's highest producing gas county, the local human services administration has seen increased demand for mental health and drug/alcohol counseling. This increased demand is a result of rapid population growth and not necessarily a reflection of increased per capita demand for services.[418] Research from "boomtowns" in the American Mountain West suggest that rapid community change can lead to additional demand for mental health services.[419]

Rapid population growth, resulting from extractive industries or any other reason, has the potential to strain a variety of local government services. If population growth increases employment in a local community, higher wages and wealth creation benefits the community in a variety of ways. However, local social service agencies may struggle to keep pace with increased demand for social services by residents who do not experience those benefits and find it more difficult to afford housing and other necessities because of price pressures. The increased demand for services may in turn increase the cost to local government to provide those services.

D. Potential impacts on recreation activities

The light, noise and land-disturbing activity associated with natural gas drilling has the potential to impact recreation areas located near well sites. The extent of those impacts will depend on the distance between drill sites and the recreation area. Shale formations in North Carolina underlie tens of thousands of acres, including a significant number of parks, game lands, bike routes, boating access points and major water bodies and other recreation areas. The fact that these recreation areas sit above the shale formation does not necessarily mean that recreational activities will be impacted if drilling occurs. If natural gas drilling occurs in North Carolina, state regulations and local zoning ordinances could mitigate impacts to these recreation areas.

Game lands

Shale formations underlie significant portions of game lands in a number of North Carolina counties. The presence of underlying shale does not necessarily mean that any given game land will be impacted; impacts are only likely to occur if drilling occurs on or nearby the game land.

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[415] Ellis, 2011; Oldham, 2012; Shactman, 2012; Zarling, 2012.
[416] Trafton, 2012.
[417] Blevins interview, 2012; Penn State Cooperative Extension, 2012.
[418] Blevins interview, 2012.
[419] Bacigalupi and Freudenberg, 1983; Kassover and McKeown, 1981.

Maps showing game lands in the Triassic Basins are shown in Appendix B: Maps of recreation areas.

Bike routes

Most bike routes in the Triassic Basins follow existing roadways. The presence of Triassic Basin shale formations underneath these bike routes does not necessarily mean they will be impacted, impacts are only likely to occur if drilling occurs on or nearby the bike routes.

Boating access points and major water bodies

Triassic Basin shale formations underlie several water bodies that North Carolinians use for recreational purposes. In the Deep River Basin, these water bodies include Jordan Lake, Falls Lake, Harris Lake, the Deep River and the Pee Dee River. In the Dan River Basin, shale formations underlie the Dan River and are close to Belews Lake. Maps showing boating access points and major water bodies in the Triassic Basins are shown in Appendix B: Maps of recreation areas.

E. Potential impacts on commercial and residential development

Many of the potential impacts associated with natural gas drilling have the potential to affect commercial and residential development. Water quality, water availability, air quality, property values, rental housing costs and many other aspects of this report each have the potential to impact trends in local and regional development. Like many other potential impacts, however, the scale of these impacts will depend on the scale of drilling activity.

Commercial development in other shale regions

Anecdotal evidence from a variety of American shale plays indicates that high levels of drilling activity can spur commercial development in a given region. In Pennsylvania's Marcellus shale regions, high demand for restaurants and hotels has encouraged proprietors to expand and invest in new equipment.[420] South Texas' Eagle Ford shale formation, similarly, has led to crowded restaurants and a dramatic increase in local sales tax revenues.[421] North Dakota's Bakken shale region has also experienced rapid increases in demand for service jobs, encouraging growth in local and regional service businesses.[422]

In some sparsely populated regions, rapid commercial growth has been constrained by labor shortages. In North Dakota's Bakken shale region, where population density is 4.8 people per square mile, businesses have had to increase wages to lure workers away from the oilfields and into local service jobs.[423]

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[420] Andree interview, 2011; Biddle, 2012; Coonley interview, 2011; Gilliland, Dec. 2011; Hanger interview, 2012; Loreno, 2011; Penn State Cooperative Extension, Aug. 2011.
[421] Collette, 2011; Smith, M., 2011; Mildenberg, Dec. 2011; Vaughan, 2011.
[422] Ellis, 2011; Falstad, 2011; Kim, 2011; MacPherson, 2011; Oakes, 2011; Soraghan, June 2011.
[423] Source: U.S. Census Bureau, 2010. Bakken shale region includes Dunn, McKenzie, Mountrail, and Williams counties; Ellis, 2011; Falstad, 2011; Shactman, 2011.

For more information on the economic potential of the shale gas industry in North Carolina, see Section 5, Potential economic impacts.

Implications of changes in rental costs

In some communities around the United States, rental housing costs have increased dramatically as drilling activity brings hundreds or thousands of workers to the drilling region. Increased demand from oil and gas industry employees, along with rising wages for local workers, has the potential to drive housing costs higher in the impacted community. (For more details on this potential impact, see Section 6.A, *Potential impacts on housing availability.*

In regions experiencing increased housing costs associated with oil and gas activity, hotels, motels and campgrounds tend to see demand increase first.[424] If drilling activity were to occur in North Carolina, these temporary housing sources would likely see temporarily increased demand. Businesses offering rentals of mobile homes, trailers or recreational vehicles would also likely see a temporary surge in demand.

Developers in some parts of the country, expecting drilling activity to continue for decades, have shown an increased interest in constructing housing options near drilling locations. These new construction projects have begun, or are in the planning stages, in rural regions of Pennsylvania, south Texas and North Dakota's Bakken shale region.[425] However, it is important to point out that housing demand from oil and gas activity is not constant over the life of the well. During the construction, drilling, fracturing and completion phases of development, large numbers of workers are required on site. After a well has been completed and the site reclaimed (typically a two to three month process), very few workers are required to maintain and monitor an individual well site.[426]

Rental housing development presents a potential problem for regions where drilling would occur over a short timeframe. If, for example, a one-year boom in drilling brought hundreds or thousands of workers to a rural region of North Carolina, newly constructed rental housing units would be underused or empty after drilling activity slows or stops. Twenty to 30 years of drilling, on the other hand, may well justify investments in hotels, motels and other rental housing options.

Industry operators in some areas with insufficient temporary housing options, contract with temporary housing providers to supply modular housing units near drilling sites. These units, known as "man camps," have sprung up in rural parts of North Dakota, Pennsylvania, and Texas.[427] Construction of these units can serve as adequate temporary housing, and lessens the need for construction of new hotels or rental housing.

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[424] Institute for Public Policy and Economic Development, 2011; Mullin and Lonergan, 2011; Patton, 2011.
[425] Andree interview, 2011; Coonley interview, 2011; Ellis, 2011; Hiller, Jan. 2011.
[426] Marcellus Shale Training and Education Center, 2010.
[427] Associated Press, Dec. 2011; Andree interview, 2011; Coonley interview, 2011; Ellis, 2011; Hiller, Jan. 2011; Hohmann, 2011; Irvine, 2011; Konigsberg, 2011; Press and Sun Bulletin, 2011.

Implications of changes in property values

For individuals interested in selling their properties, higher property values clearly have a beneficial impact. For individuals who wish to remain on their properties and *not* lease their mineral rights, property taxes may increase without a commensurate increase in cash for the landowner.

Water supply issues in commercial and residential development

Residents from many parts of the country have expressed concern over potential water contamination associated with hydraulic fracturing, as well as the volume of water required to fracture a well. Researchers continue to collect data, analyze information and pursue these questions vigorously. As of this study, no scientific consensus has been reached as to whether shale gas exploration and production causes systematic groundwater contamination. Other sections of this study will address potential impacts on water quantity in North Carolina if shale gas development were to begin in North Carolina.

Water, of course, is a crucial component to any commercial or residential development project. Without adequate water supply, a wide variety of construction, manufacturing and other business activities would cease to be viable. Without sufficient water supply or adequate water quality, residential development would also be severely damaged.

Public perception of water threats, whether grounded in science or not, could impact demand for future residential development near sites where shale gas exploration and development has or will take place. As of this report, however, no clear evidence has been found indicating that water quantity or quality problems associated with shale gas exploration and development have diminished the viability of commercial or residential development projects.

F. Potential noise impacts

Natural gas development, like many industrial activities, involves significant amounts of noise, especially during the initial phases of well pad construction, drilling, hydraulic fracturing and site reclamation. These activities typically last two to three months per well pad, and involve heavy machinery, large trucks and generators that could impact nearby communities.[428] After a well is completed, sustained production generates minimal noise.[429] However, each individual well may be re-fractured in the future, when truck activity could pick up once again.

The U.S. Department of Housing and Urban Development (HUD) uses the following scale to determine acceptable and unacceptable noise levels for different types of land use. This scale can be used as a reference for noise levels related to shale gas development:

[428] Hefley, 2011; NYSDEC, 2011.
[429] NYSDEC, 2011.

Table 6-2. HUD Daytime Land Use Compatibility Guidelines for Noise

Land Use Category	Clearly Acceptable	Normally Acceptable	Normally Unacceptable	Clearly Unacceptable
Residential	<60	60-65	65-75	>75
Livestock farming	<60	60-75	75-80	>80
Office buildings	<65	65-75	75-80	>80
Wholesale, industrial, manufacturing, utilities	<70	70-80	80-85	>85

Access road construction

Before activity at a well site can begin, access roads must be planned and constructed to allow the necessary equipment to move into place. Construction of access roads typically takes three to seven days, and occurs during the daytime.[430] Like any road construction, this process requires a number of heavy machines, and produces noticeable noise impacts.

The tables included in this section show average noise levels associated with each phase of construction related to drilling operations. They show decibel levels are various distances from the noise source. The decibel scale is logarithmic, meaning an increase of 10 decibels represents a tenfold increase in volume. (See appendix XX for decibel levels of common noise sources). These noise levels do not take into account noise reduction due to ground attenuation, atmospheric absorption, vegetation or topography.

Table 6-3. Distance in Feet/Sound Pressure Levels in Decibels

Access Road Construction	Quantity	Percent of time in use	50 ft	250 ft	500 ft	1000 ft	1500 ft	2000 ft
Excavator	2	40%	80	66	60	54	50	48
Grader	2	40%	84	70	64	58	54	52
Bulldozer	2	40%	81	67	61	55	51	49
Compactor	2	40%	79	65	59	53	49	47
Water truck	2	40%	75	61	55	49	45	43
Dump truck	8	40%	81	67	61	55	52	49
Loader	2	40%	78	64	58	52	48	46
Composite Noise			**89**	**75**	**69**	**63**	**59**	**57**

Source: New York State Dept. of Environmental Conservation

These noise levels indicate that residents or businesses located 2000 feet from access road construction would experience an average noise level of 57 decibels. This noise level is roughly equivalent to the noise levels associated with everyday conversations. Fifty feet from the construction site, however, residents or businesses could experience 89 decibels, similar to a shouted conversation.

[430] Ibid.

Pad construction

Once access roads are laid, construction can begin on the well pad itself. This process requires grading the land and, in some cases, clearing vegetation to prepare for the arrival of drilling equipment. The types of noise generated during this phase are common to other industrial construction projects, including noise from bulldozers, excavators and a variety of trucks. Well pad construction lasts, on average, seven to 14 days, and typically occurs during daytime hours.

The table below indicates levels of noise associated with key equipment used in the construction of the well pad. This table does not include the noise from roughly 45 round-trip truck trips required to bring materials to the site.

Table 6-4. Distance in Feet/Sound Pressure Levels in Decibels

Well Pad Construction	Quantity	Percent of time in use	50 ft	250 ft	500 ft	1000 ft	1500 ft	2000 ft
Excavator	1	40%	81	63	57	51	47	45
Bulldozer	1	40%	82	64	58	52	48	46
Water Truck	1	40%	76	58	52	46	42	40
Dump Truck	2	40%	76	61	55	49	45	43
Pickup Truck	2	40%	75	60	54	48	44	42
Chain saw	2	40%	84	66	60	54	50	48
Composite Noise			**84**	**70**	**64**	**58**	**55**	**52**

Source: New York State Dept. of Environmental Conservation

These noise levels indicate that residents or businesses located 2,000 feet from well pad construction could experience average noise levels of 52 decibels. This noise level is roughly equivalent to the noise levels associated with a quiet electric toothbrush. Fifty feet from the construction site, however, residents or businesses could experience 84 decibels, similar to a gasoline-powered handsaw.

Vertical and horizontal drilling

The vertical and horizontal drilling process associated with shale gas extraction is the longest-lasting phase of construction. Once all equipment is in place, drilling lasts, on average, 28 to 35 days. More significantly, drilling is a 24-hour operation. Sound generated in the evening hours typically travels further and can have a more significant impact than sounds generated in the daytime. Some major pieces of equipment required for the drilling phase include:

- Diesel engines for the drill rig. The noise levels of these engines fluctuate depending on engine speed and the weight of the load.
- Air compressors powered by diesel engines. These units generate the loudest noises of the drilling stage. The exact number of compressors required for each well varies. Generally, more compressors are required as drilling advances.
- Tubular preparation and cleaning. Before sections of pipe are laid into the ground, workers hammer the outside of each pipe to clear internal debris. This process generates an acute noise every 20 to 30 minutes during drilling, and has generated a

significant number of complaints from nearby landowners, especially during evening hours.[431]

- Drill pipe connections. Before rig workers can connect one length of pipe to another, they must release highly pressurized air that has been built up in the well. This release generates a high frequency noise, and occurs at 20 to 30 minute intervals during drilling.
- Truck trips. Roughly 355 round-trip heavy truck trips are required to bring materials to the well site during drilling.[432]

Table 6-5 indicates levels of noise associated with equipment involved in vertical and horizontal drilling. During the drilling process, the sound level remains roughly constant at the composite noise level. Noise impacts from drilling will likely be higher at night, since ambient noise levels are typically lower in the evening.

Table 6-5. Distance in Feet/Sound Pressure Levels in Decibels

Vertical Air Well Drilling	Quantity	50 ft	250 ft	500 ft	1,000 ft	1,500 ft	2,000 ft
Drill rig drive engine	1	71	57	51	45	41	38
Compressors	4	77	63	57	51	47	45
Hurricane booster	3	51	37	31	25	22	19
Compressor Exhaust	1	51	37	31	25	21	18
Composite Noise		**79**	**64**	**58**	**52**	**48**	**45**

Table 6-6. Distance in Feet/Sound Pressure Levels in Decibels

Horizontal Drilling	Quantity	50 ft	250 ft	500 ft	1000 ft	1500 ft	2000 ft
Rig Drive Motor	1	71	57	51	45	41	38
Generator	1	51	37	31	25	22	19
Top Drive	1	65	51	45	39	35	33
Draw Works	2	60	46	40	34	30	28
Triple Deck Shaker	2	75	61	55	49	45	43
Composite Noise		**76**	**62**	**56**	**50**	**47**	**44**

Source: New York State Dept. of Environmental Conservation

These noise levels indicate that residents or businesses located 2,000 feet from well pad construction could experience average noise levels of 44 to 45 decibels during the drilling phase. This noise level is roughly equivalent to the noise levels associated with a typical office space. Fifty feet from the construction site, however, residents or businesses could experience 76 decibels, similar to a loud air conditioner or washing machine.

[431] NYSDEC, 2011.
[432] Truck trips include rig equipment, drilling fluids, non-rig drilling equipment, rig mobilization, completion chemicals, and completion equipment.

Hydraulic fracturing

Hydraulic fracturing requires up to 20 high-powered pumping trucks operating for two to five days, 24 hours per day. These trucks maintain the water pressure required to create fissures in the shale formation, and are powered by diesel engines that create a significant amount of noise. The amount of noise at any given time depends on the rotation speed of the diesel motor, which varies during the fracturing process. Noise from these pumper trucks is most noticeable in the low-frequency spectrum (50-250 Hertz).

Hydraulic fracturing also requires a large number of truck trips to supply the site with water, sand, chemicals and other items required to fracture a well. On average, 843 round-trip heavy truck trips are required for each fracturing of a well.[433] However, some fracturing operations transport their water through pipelines, significantly reducing the number of truck trips required per well.[434]

Table 6-7 indicates levels of noise associated with each phase of hydraulic fracturing. During the fracturing process, the sound level remains roughly constant at the composite noise level. Noise impacts from fracturing will likely be higher at night, since ambient noise levels are typically lower in the evening.

Table 6-7. Distance in Feet/Sound Pressure Levels in Decibels

Hydraulic Fracturing	Quantity	50 ft	250 ft	500 ft	1000 ft	1500 ft	2000 ft
Diesel Pumper Trucks (op. 1)	20	99	85	79	73	69	67
Diesel Pumper Trucks (op. 2)	20	104	90	84	78	74	72

Source: NYSDEC, 2011.

These noise levels indicate that residents or businesses located 2,000 feet from a hydraulic fracturing site would experience noise levels of 67 to 72 decibels during the fracturing operation. This noise level is roughly equivalent to the noise levels associated with freeway traffic. Fifty feet from the construction site, however, residents or businesses could experience 99 to 104 decibels, similar to the sounds of a loud motorcycle.

[433] Truck trips include fracturing equipment, fracturing water, fracturing sand, and produced water disposal. Estimates are based on 5 million gallons of fracturing water required per well.
[434] Murphy, Thomas. Presentation at Duke University, Jan. 9, 2012.

Figure 6-10. Hydraulic Fracturing in Upshur Valley, West Virginia (Marcellus region)

Source: Chesapeake Energy, 2008, via NYSDEC, 2011.

Site reclamation and sustained production

Site reclamation involves construction equipment similar to that used in well pad construction. During the reclamation process, heavy machinery restores the land surrounding the well pad to its natural state. The noise impacts from this process will likely be similar to that experienced during well pad construction phase.

During sustained production, noise from the wellhead is minimal. Occasional vehicle noise from well site monitors would be the primary noise generator during this phase, which can last seven to 10 years or more. Mowing of the well site also occurs during this phase.

Pipeline construction

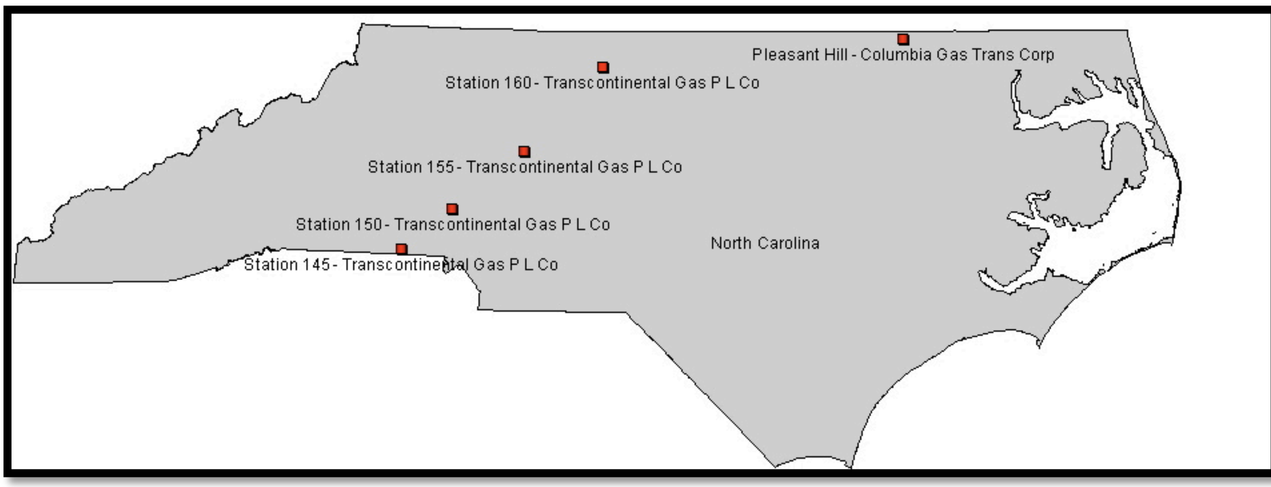
Underground natural gas pipelines are required to transport gas from a production pad to a distribution network. Most of the noise impacts would be generated by heavy equipment commonly used for clearing, grading and construction activities. Since construction progress moves forward over time, nearby communities would likely experience noise impacts sequentially and temporarily. The most noise-intensive step in pipeline construction would be pipe stringing, in which individual lengths of pipe are joined together above ground, and specialized equipment makes any necessary adjustments, such as bending lengths of pipe.

Compressor stations

Natural gas pipelines require compressor stations at 40 to 100 mile intervals to maintain the appropriate level of pressure in the pipeline.[435] Residents in a variety of locations, including Arkansas, Pennsylvania and Texas have voiced concerns over noise levels associated with compressor stations in recent years.[436] Currently, there are five natural gas compressor stations in North Carolina.[437]

Noise levels at some natural gas compressor stations can approach 90 decibels, similar to the noise generated by a loud blender.[438] In some states, such as Arkansas, the state Oil and Gas Commission has adopted rules to limit noise emissions from compressor stations to 55 decibels.[439]

Figure 6-11. Natural Gas Compressor Stations in North Carolina



Source: U.S. Energy Information Administration

Station 145, Transcontinental Gas Pipeline Co., Cleveland County

Station 150, Transcontinental Gas Pipeline Co., Iredell County

Station 155, Transcontinental Gas Pipeline Co., Davidson County

Station 160, Transcontinental Gas Pipeline Co., Rockingham County

Pleasant Hill Station, Columbia Gas Transmission Co., Northampton County

G. Potential visual impacts

Natural gas drilling and construction in North Carolina would introduce a number of unusual landscape features, such as drilling rigs, nighttime lighting and natural gas flaring. Some of

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[435] Naturalgas.org website.
[436] Burnett, 2009; Glover, 2011; Hankins, 2009; Legere, 2011.
[437] Personal correspondence, U.S. Energy Information Administration, Jan. 2012.
[438] Sierra Club website, 2011.
[439] Glover, 2011.

these visual impacts could be perceived by residents and visitors to the area as detrimental. Each of these features would be temporary; once a well has been completed, visual impacts would be minimal.

Since North Carolina has little history of drilling for oil and natural gas, many residents could experience an unfamiliar set of visual impacts associated with drilling and hydraulic fracturing. These impacts may be most noticeable in rural areas, where residents are accustomed to farmland, open spaces and forested areas.

Access road and pad construction

Construction of the access roads to a well pad site requires equipment similar to construction of any small to medium-sized road. An access road to a well site looks very much like an unpaved access road on a farm. Pad construction involves heavy equipment including bulldozers, excavators and other heavy trucks. The visual impacts from these activities would last approximately 10 to 21 days, and would be visible during normal daytime hours. Well pads cover, on average, 3.5 acres of land, with additional land required for water storage ponds and equipment staging areas.[440]

New techniques have enabled drilling operators to occupy a smaller surface area than in previous decades. By drilling multiple wells from a single pad and using underground horizontal drilling, companies can minimize the amount of acreage required to access natural gas from a surrounding area. When compared with traditional vertical drilling techniques, this technology reduces the visual impact of the well pads and associated construction in a drilling area.

Figure 6-12. Accessing Shale Field via Vertical Drilling

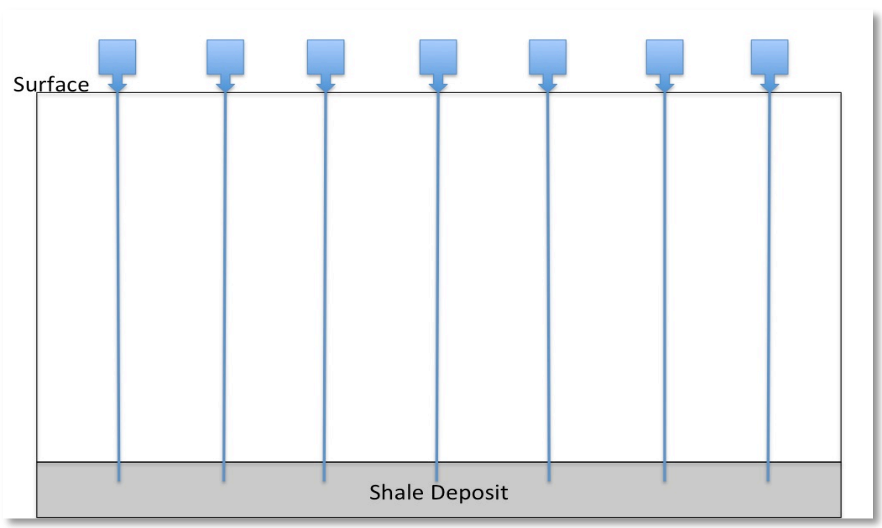

Image by Daniel Raimi, 2012

[440] NYSDEC, 2011.

Figure 6-13. Accessing Shale Field via Horizontal Drilling

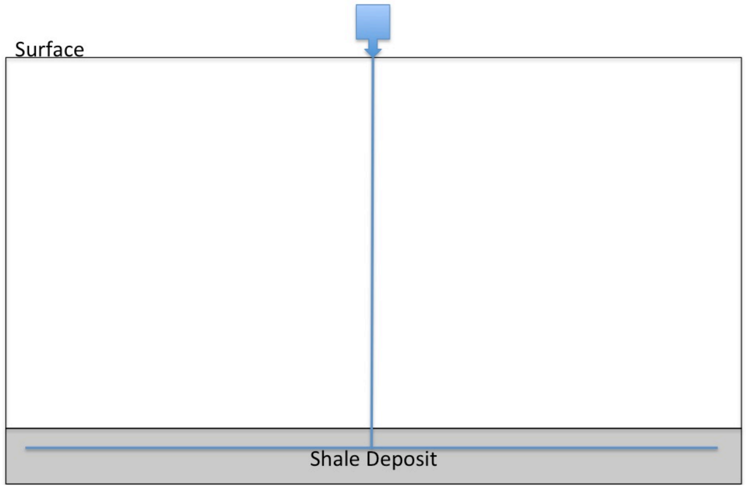

Image by Daniel Raimi, 2012

Drilling, lighting and storage

Natural gas drilling rigs can range in height from 40 feet for a single rig to 150 feet for a triple rig.[441] Rigs are typically in place for 28 to 35 days, and create a significant visual impact in the vicinity of the site. Typically, one drilling rig is used per well site; however, at multi-well sites, two drilling rigs could be used simultaneously on the same well pad.[442] In forested landscapes, drilling rigs sometimes resemble cell phone towers or radio transmitters.

Since drilling activities continue 24-hours per day, powerful lights illuminate the well site to increase worker safety. Lights are often directed across the drilling pad, providing maximum coverage of the site, but also creating an impact on areas directly adjacent to the drilling site.[443] States such as Colorado and Louisiana have created buffer zones of 800 and 300 feet, respectively, between drilling sites and roads to minimize glare for passing drivers.[444] Visual impacts from lighting could also be decreased by instructing drilling operations to direct their lighting downwards, instead of across the well pad.

During the drilling process, drilling fluids, cuttings, mud and other discarded materials must be stored near the well site. These discarded elements may be housed in plastic or steel containers, or in open "drilling pits." When drilling pits are employed, they are typically lined with plastic, and located adjacent to the well site.[445]

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[441] Single rigs are capable of holding one length of piping at a time, while triple rigs can hold up to three connected lengths of piping at a time.
[442] NYSDEC, 2011.
[443] Upadhyay and Bu, 2010.
[444] NYSDEC, 2011.
[445] Ibid.

Hydraulic fracturing, flaring and water impoundments

Hydraulic fracturing requires a large number of heavy trucks and heavy equipment moving to and from the well site over the course of two to five days. During this time, approximately 843 round-trip heavy truck trips are required to complete the fracturing process.[446] These trucks are visible on roadways and in staging areas, where they collect water, coordinate activities or simply wait until they are needed. Trucks and other specialized equipment are sometimes stored on unreclaimed well pads, creating a longer-lasting visual impact on a well site.[447]

Flaring of natural gas at the well site is sometimes necessary in the 12 to 24 hour period after hydraulic fracturing has been completed. During this period, wells produce a large volume of flowback water, and gas is flared instead of captured for storage or transport.[448] Flaring can have a significant impact, especially in the nighttime hours. In Bradford County, Pa., intense flaring from newly drilled wells led a township supervisor to proclaim: “You don’t need a nightlight.”[449] Flaring also has the potential to disturb local residents, who sometimes see it as a sign of decreased tranquility in their community.[450]

Surface water impoundments are also required near hydraulic fracturing sites. Typically, one water impoundment services the water requirements of wells within a four-mile radius.[451] These impoundments are typically lined with plastic, and hold water before it is used in the fracturing process. Freshwater impoundments can hold millions of gallons of water, and can cover up to five surface acres of land.[452] These impoundments can be visible from miles away, and easily seen from the air.[453] Water-hauling trucks would make regular trips to and from such impoundments, which would likely increase traffic and noise in the surrounding areas.

Water impoundments can also be used for on-site flowback water storage. States regulate the requirements for storage of this water differently, and in some instances allow for flowback water to be stored in open, lined pits. These pits can cover acres of surface area, and can also emit smells that bother nearby residents.[454]

Completion and reclamation

Once a well is drilled and fractured, a “Christmas tree” is placed on top of the wellhead to manage and distribute the natural gas. This piece of equipment is fairly small, and would cause minimal visual impact. Additionally, two to three storage tanks to handle flowback water are installed near the well. These tanks range in size from five to 10 feet tall, with a diameter of

[446] Ibid. Truck trips include fracturing equipment, fracturing water, fracturing sand and produced water disposal. Estimates are based on 5 million gallons of fracturing water required per well.
[447] Upadhyay and Bu, 2011.
[448] NYSDEC, 2011.
[449] Long, 2010.
[450] Andree interview, 2011; Coonley interview, 2011; Raybuck interview, 2011; Roth interview, 2011.
[451] NYSDEC, 2011.
[452] Ibid.
[453] Upadhyay and Bu, 2011.
[454] Gregory, Kelvin. Presentation at Duke University, Jan. 9, 2011; Griswold, 2011; Plikunas et al, 2011.

between five and 10 feet.[455] With no obstacles in their line of site, they can be visible from up to three miles away. However, trees, brush or other vegetation could easily obscure the wellhead and storage tanks. These objects remain in place for the productive life of the well. While visual impacts of brine storage tanks can be small, the tanks sometimes emit odors that can disturb nearby residents.[456]

Reclamation of the well site requires additional trucks and heavy machinery. The visual impacts of restoration are temporary and would be similar to those experienced during well pad or access road construction.

Pipeline construction

Pipeline construction has the potential to have significant visual impacts in North Carolina. Before pipelines can be laid in the ground, workers must clear trees and other materials within the pipeline's right of way. These clearings must be maintained during the pipelines operational lifetime, as workers need access to the area for maintenance and inspections.

The visual impacts associated with pipeline construction are typically long, thin corridors, similar to the clearing produced for overhead power lines. Currently, North Carolina has 2,848 miles of natural gas pipeline in place.[457] None of these pipelines are gathering lines, which would be needed to transport gas from the wellhead to the larger interstate and intrastate lines. North Carolina may also need additional interstate and intrastate lines, if gas development comes to the state. Table 6-8 gives the length, in miles, between Sanford, N.C., and the five compressor stations currently operating in North Carolina.

Table 6-8. Distances, in Miles, Between Potential Shale Regions and North Carolina Compressor Stations*

	Sanford	Durham	Madison	Wadesboro
Transco Station 145 **Cleveland County, N.C.**	133	156	116	85
Transco Station 150 **Iredell County, N.C.**	98	112	66	72
Transco Station 155 **Davidson County, N.C.**	60	73	44	56
Transco Station 160 **Rockingham County, N.C.**	76	65	0	98
Columbia Pleasant Hill Station **Northampton County, N.C.**	117	85	135	179

Source: distancecalculator website.

* Note: All distances measured "as the crow flies."

[455] Upadhyay and Bu, 2011.
[456] Gregory, Kelvin, Presentation at Duke University, Jan. 9, 2011.
[457] Source: U.S. Energy Information Administration.

Pipelines also require compressor stations to maintain proper flow of the natural gas. These stations vary in size, depending on the volume of the gas flowing through the pipeline. Compressor stations are typically required every 30 to 40 miles along a pipeline, and could generate some visual impacts depending on their location and size.

Figure 6-14. Drilling Rig from Two Miles

Source: Uphadyay and Bu, 2011

Figure 6-15. Marcellus "Double Rig"

Source: NPR State Impact, Pennsylvania

Figure 6-16. Hydraulic Fracturing Operation, Canadian County, Oklahoma

Source: Society of Petroleum Engineers website, JPT.com

Figure 6-17. Lighting and Natural Gas Flaring at a Marcellus Natural Gas Well, Pennsylvania

Source: Naturalgasforums.com website

Figure 6-18. Brine Tanks at a Producing Well, Bradford County, Pennsylvania

Source: Uphadyay and Bu, 2011

H. Potential impacts on crime rates

Major discoveries of oil and gas throughout the history of the United States have been accompanied by rapid population growth in the area of the "play."[458] This surge in population, whether in Pennsylvania in the 1860s, Texas in the early 1900s or in modern-day Williston, North Dakota, is primarily composed of young men – skilled in jobs associated with oil and gas extraction, and often living apart from friends, family and social support networks.[459] In some cases, these men lived and worked in cramped quarters, in rural communities that were unprepared for the population surge that accompanied the energy boom.

Examples from other states

Sociological literature indicates that in some energy boomtowns, crime rates increase at a faster rate than population growth.[460] Most of this research was carried out in rural parts of the American West, as high oil prices drove growth in energy development during the late 1970s and early 1980s.

Stories of increased crime and other social problems have also emerged in some modern energy boomtowns. In northeast Pennsylvania, local officials and newspapers have reported increases in crime rates due to the influx of workers in the natural gas industry, especially drunk driving charges.[461] In Sublette County, Wyo., increased drilling activity has, according to local officials, led to dramatic increases in drug usage and crime rates.[462] North Dakota's Bakken shale region has also seen reports of increased crime rates associated with the boom in oil production.[463]

Drug use has also been a concern among workers in the modern oil and gas industry. In a 2010 survey of natural gas employers in Pennsylvania's Marcellus region, 12 percent described drug use as a "very big challenge," and 53 percent cited drugs as "somewhat of a challenge" in finding new employees.[464] This issue, of course, is not unique to the oil and gas industry. News reports and magazine articles from Pennsylvania, Texas, Colorado, and Wyoming have cited drug use, particularly methamphetamine, as a problem in some drilling communities.[465]

Research and reporting from some states also suggests that rates of sexually transmitted diseases (STDs) may increase alongside oil and gas activity. One northern Pennsylvania hospital cited increased demand for treatment of STDs, drug problems and construction or drilling-related injuries.[466] Other research suggests that energy development projects may be linked to

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[458] Yergin, 1991.
[459] Gilmore, 1976; Kassover and McKeown, 1981; Konigsberg, 2011; Massey et al, 1976; Massey 1980; Yergin, 1993.
[460] Brookshire and D'Arge, 1980; Covey and Menard, 1983; Freudenberg and Jones, 1991; Kohrs, 1974; Krannich et al., 1989; Little, 1976-77.
[461] Blevins interview, 2012; Levy, 2011; Long, 2010; Needles, 2011; Pennsylvania Budget and Policy Center, 2011.
[462] Fuller, 2010; Sublette County, WY website, 2011.
[463] Ellis, 2011; Levy, 2011; Oldham, 2012; Shactman, 2012; Springer, 2012.
[464] Marcellus Shale Education and Training Center, 2010.
[465] Chakrabarty 2007; Fuller, 2010; Porter, 2011.
[466] Covey, S. 2010.

more risky sexual behavior in youth, leading to higher rates of STDs.[467] In these examples, it is unclear whether these rate increases occur in the local population or reflect STD rates among transient oil and gas crews.

The research, newspaper reports and anecdotes described above do not reflect all communities that have experienced growth in natural gas or oil development. While some (mostly rural) regions of the country report increases in crime rates and other social problems, no modern empirical research has found a causal relationship between increased oil and gas activity and increased crime rates.

A recent study by researchers at Pennsylvania State University found no empirical evidence of increased crime associated with drilling in the Marcellus region.[468] Newspapers from the regions around Texas' Eagle Ford and the Barnett shale plays, Oklahoma's Woodford shale and Louisiana's Haynseville and Fayetteville shales have not reported upticks in crime. Similarly, counties in southwest Pennsylvania, where Marcellus drilling has boomed in recent years, have not reported significant increases in any of these social problems.[469]

Statistical analysis overview

As part of the analysis of potential social impacts, DENR conducted a statistical analysis of crime rates in six regions of the United States that have experienced major growth in the oil and/or gas industry over the past three to five years. These regions are Colorado's Western Slope, all of Oklahoma, Pennsylvania's Marcellus shale region, Texas' Barnett and Eagle Ford shale plays, North Dakota's Bakken shale region, and Wyoming's Green River Basin.[470]

The analysis compares changes in levels of oil and gas production in relevant counties with the reported rates of a variety of crimes. The analysis controls for factors other than oil and gas development that could potentially impact crime rates in each county.

This statistical analysis comes with certain limitations. Since the data comes from the county level, it may not capture trends occurring at more localized levels. For example, crime rates may change dramatically in a small town where drilling has occurred without significantly affecting countywide crime statistics. In that case, a county-wide analysis may not reflect the small town's experience. This limitation may be particularly present in counties that cover a large physical area (like Wyoming's large counties), or counties with large populations (such as in Texas' Barnett region).

Statistical analysis results[471]

In some heavily drilled regions, the data show a small but significant relationship between increased drilling activity and crime rates. These impacts vary by region, with counties in Colorado and Wyoming showing increased rates in violent crimes associated with increased

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[467] Goldenberg et al, 2008.
[468] Kowalski and Zajac, 2012.
[469] Interviews from Armstrong, Butler, and Westmoreland counties, PA.
[470] Based on a survey of accessible local and regional newspapers, radio, and television outlets.
[471] For information on data, methods, sources, and detailed results, please see Appendix D: Statistical analysis methodology.

rates of natural gas production. In Texas, however, both the Eagle Ford and the Barnett shale regions showed decreased rates in assorted crimes associated with increased natural gas production.

In Colorado's Western Slope region, increased rates of natural gas production were strongly correlated with slightly elevated rates of aggravated assault (99 percent significance level). The strong relationship between aggravated assault and gas production helped drive a significant relationship between increased gas production and elevated rates of violent crime (95 percent). Interestingly, the data also show that increased oil production in Colorado counties was significantly related to *decreased* reported cases of rape (99 percent).

In Wyoming's Green River Basin region, strong growth in oil and gas production were both positively correlated with elevated rates of certain crimes. Increased production of natural gas showed a statistically significant relationship with slightly elevated rates of aggravated assault and overall violent crime (both 99 percent significance level). Increased rates of oil production were correlated strongly with elevated rates of murder (95 percent), burglary (95 percent), non-violent crime (99 percent), and overall crime (99 percent).

In Texas, both the Barnett and Eagle Ford shale regions showed increased rates of gas production to be strongly correlated with *decreased* rates of certain crimes. In the Eagle Ford region, increased natural gas production correlated strongly with a slight decrease in murder rates (99 percent significance level). In the Barnett shale region, increased natural gas production showed a strong relationship with slightly lower rates of burglary (95 percent), larceny (99 percent), and overall non-violent crimes (99 percent). Neither region showed a significant relationship between increased oil production and crime rates.

North Dakota's Barnett shale region, all of Oklahoma, and Pennsylvania's Marcellus shale region showed no significant relationships between changes in oil and gas production and crime rates.

Discussion of results

The results of these state-level analyses leave several important questions unanswered and pose new questions for further research. While the analysis controls for a variety of factors, the limited amount of data means that none of these findings establish that oil or gas drilling directly cause either high or low crime rates. The results do not show that oil or gas workers were responsible for either high or low crime rates. Oil and gas workers may be the perpetrators of crimes, the victims of crimes, or both. Further research is required to accurately answer this question.

Second, the results do not show a clear pattern with regard to impacts related to rural versus urban settings. If rural regions experienced stronger relationships between oil and gas production and crime rates, North Dakota's Bakken shale region would show the strongest relationship, and Texas' Barnett shale region would show the weakest. However, the results are mixed. Colorado and Wyoming, where drilling regions are sparsely populated, show significant relationships between increased drilling and high crime rates, but sparsely populated drilling regions in North Dakota and Texas do not.

In Texas' Barnett and Eagle Ford regions, significant relationships between increased drilling and *low* crime rates defy the "boomtown effect" narrative. The reason for this relationship is unclear, but may be related to the fact that many oil and gas workers live in Texas. Given Texas' long history in the oil and gas industry, its local workforce is more able to work close to home, limiting the impact of a transient workforce experienced in more typical "boomtowns."

High rates of violent crime can be linked to diminished social cohesion in a community.[472] Since Texas has a long history of drilling, and a local workforce trained to work on oil and gas rigs, increased oil and gas production in Texas may not significantly disrupt community character or population characteristics. In areas where the oil and gas workforce must be imported, such as Colorado and Wyoming, community disruption would be more likely to occur. However, North Dakota and Pennsylvania, two regions without a strong local oil and gas workforce, defies this explanation, as no significant relationships were found between increased drilling and crime rates.

The types of crime driving this analysis also merit discussion. In Colorado and Wyoming, aggravated assault rates showed strong relationship with increased natural gas production. Aggravated assault, while a serious crime, does not typically have the disruptive effect on communities that crimes like murder or robbery do. Bar fights, for example, may be classified as aggravated assaults. Issues of community division (see section 6.I, *Community Impacts*) related to oil and gas production could contribute to increases in aggravated assaults.

Data analysis limitations

The data used in this study are limited, and additional research is required to confirm or refute the findings. For example, population data on transitory workforces is very difficult to obtain. As a result, natural gas and oil production is used as a proxy for the population changes that may impact crime rates when drilling activities occur. Since oil and gas production peaks at a well site after completion of the well, production rates are an imperfect measure of population changes in a community. Production peaks may lag behind population changes by weeks or months, depending on when natural gas gathering lines have been installed.

Second, workers may not be living and spending their off hours in the counties where oil or gas production occurs. As noted in Section A, Potential impacts on housing availability, workers sometimes commute an hour to and from their worksite. In areas where housing supplies are short, workers are especially likely to live some distance from the well pad. As a result, oil or gas production in any given county does not necessarily align with population or community changes in that county.

Third, policing tactics likely differ between counties and states, which may impact the data. Methods of policing are not controlled for in this analysis.

Fourth, the data for crime reporting may not fully reflect crime rates in the counties analyzed. Uniform Crime Reports, compiled for each county, are the sole tool for assessing changes in crime rates in this analysis. However, other indicators of crime, such as calls to local police,

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[472] Mazerolle et al., 2010; Sampson et al., 1997; Sampson and Raudenbush, 1999.

number of traffic stops and data on unreported or underreported crimes would be useful to paint a more complete picture.

Implications for North Carolina

If natural gas drilling occurs in North Carolina, it will not necessarily experience the impacts of a typical "boomtown." Local and regional characteristics play a large part in determining how communities interact with any new development. The anecdotal reports and statistical analysis described above indicates that problems with crime may occur in some drilling communities, but whether or not these problems will occur in North Carolina is not predictable.

One potential factor in determining if oil or gas development may impact crime is whether or not companies hire locally. Since North Carolina does not have a trained workforce in natural gas development, the state can expect many of the drilling crews to come from other parts of the country. Industry workers often travel without their families.[473] Since changes in crime rates are often related to changes in community character, an influx of workers from out of state may increase the likelihood of crime impacts.[474]

Local infrastructure and population density may also play a role in determining if an influx of new workers impacts local crime rates. Preliminary research in Pennsylvania finds that rural areas were impacted more strongly by social disruptions (though not necessarily crime) associated with the natural gas industry.[475] Likewise, anecdotes of social problems and increased crime rates primarily come from more sparsely populated regions in northeast Pennsylvania, Colorado, Wyoming and North Dakota.[476]

Population density varies greatly between potential areas of exploration in North Carolina and areas that have documented increased crime rates related to oil and gas development. Table 6-9 compares the population densities of North Carolina's Dan and Deep River basins with impacted regions of Pennsylvania, Wyoming and North Dakota.

[473] Fuller, 2010; Levy, 2011; Long, 2010; Needles, 2011; PA Budget and Policy Center, 2011; Interviews, 2011.
[474] Mazerolle et al., 2010; Sampson et al., 1997; Sampson and Raudenbush, 1999.
[475] Brasier and Filteau, 2010.
[476] Blevins interview, 2012; Ellis, 2011; Fuller, 2010; Levy, 2011; Sublette County website, 2011.

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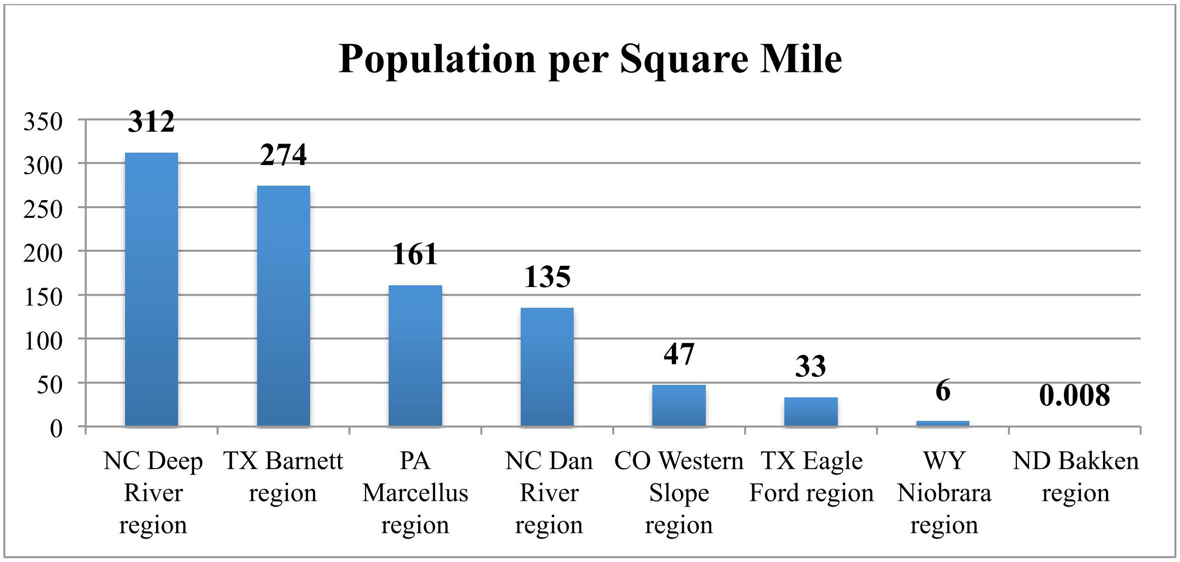
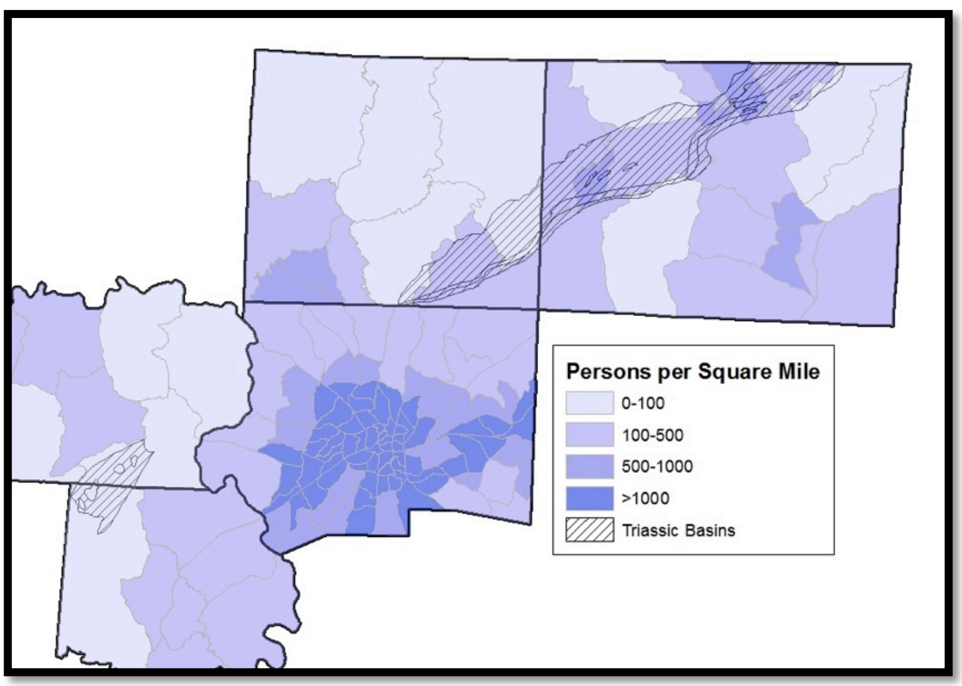
Table 6-9. Population Densities in Oil/Gas regions, and in the North Carolina Deep and Dan River Basin Regions



Source: U.S. Census 2010.

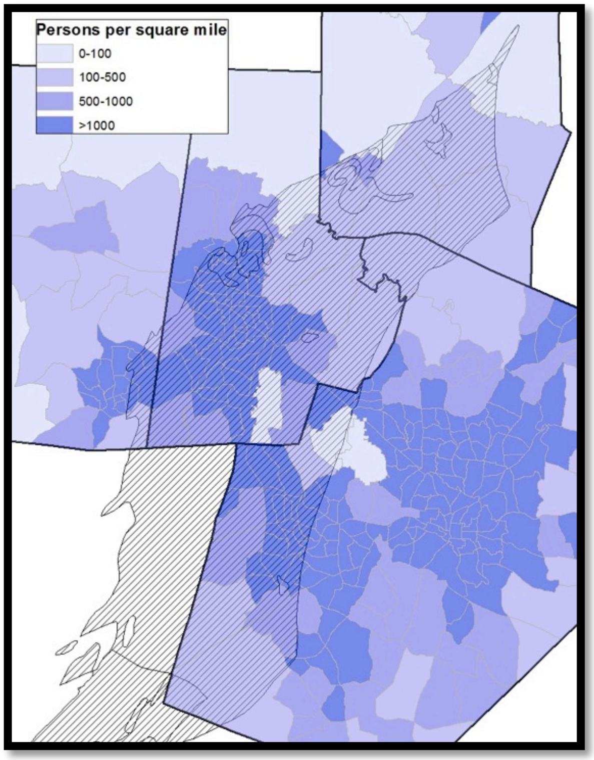
Clearly, North Carolina's shale formation regions have significantly higher population densities than some of the areas experiencing crime impacts associated with drilling projects. If higher population density lessens crime impacts, North Carolina would likely not experience the same level of impact as its more rural counterparts in Wyoming or Colorado.

Figure 6-19. Dan River Basin Population Density



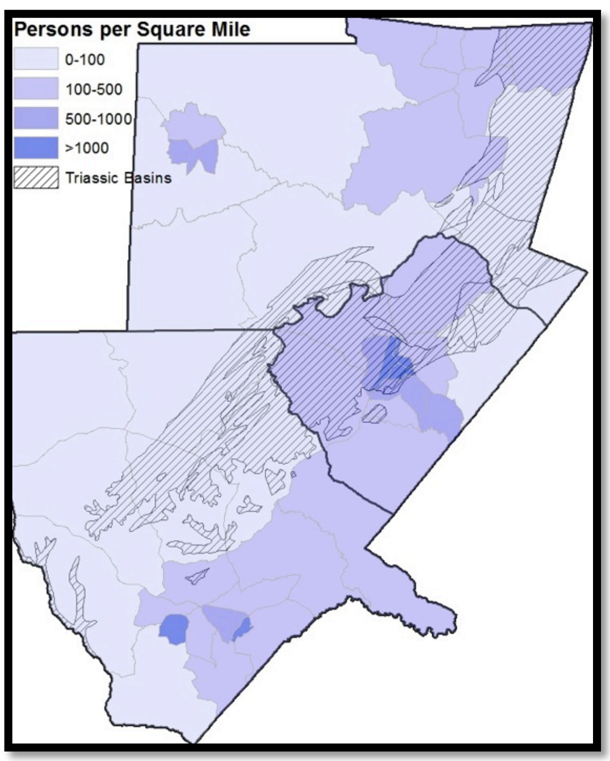
Source: U.S. Census Bureau, NC Onemap geospatial data, N.C. Geological Survey

Figure 6-20. Durham Sub-basin Population Density



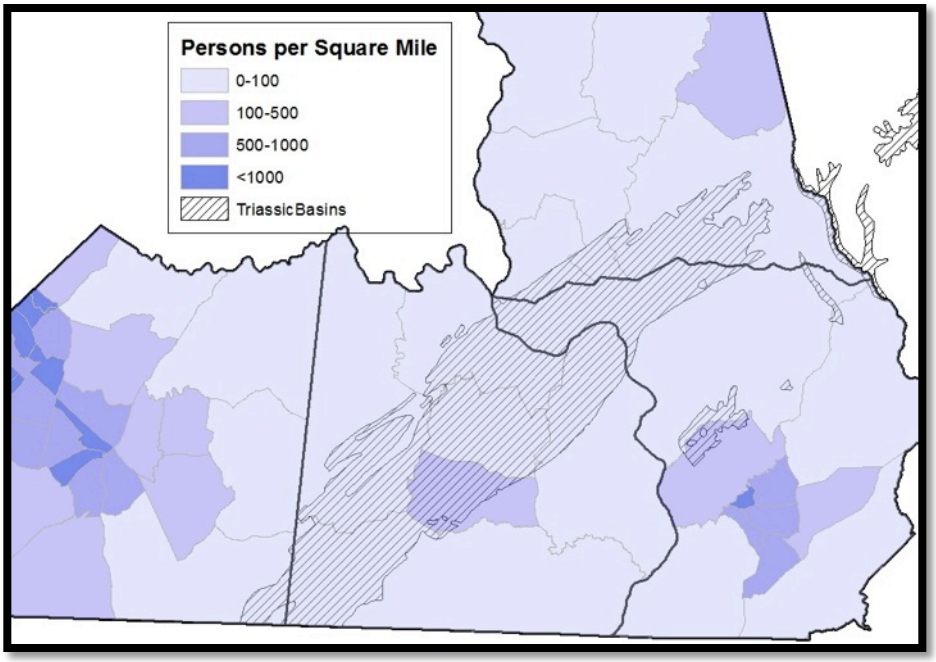
Source: U.S. Census Bureau, NC Onemap geospatial data, N.C. Geological Survey

Figure 6-21. Sanford Sub-basin Population Density



Source: U.S. Census Bureau, NC Onemap geospatial data, N.C. Geological Survey

Figure 6-22. Wadesboro sub-basin population density



Source: U.S. Census Bureau, NC Onemap geospatial data, N.C. Geological Survey

I. Potential community impacts

Natural gas drilling has the potential to affect community dynamics in both rural and urban areas. Some residents will favor drilling, while others will oppose it; this divide can affect relationships between friends, neighbors and community groups. Natural gas drilling also has the potential to significantly change the character of a community by introducing an industrial-scale activity to a previously quiet rural area.

Distributional impacts and potential for community division

If gas drilling occurs in North Carolina, some residents will benefit more than others. Uneven distribution of benefits and costs from drilling activity, while a natural result of economic processes, has the potential to create divisions within communities. While some residents may benefit substantially from drilling, most members of the community will experience the impacts of gas production, such as visual impacts, noise, traffic and a potential increase in rental housing costs. In particular, landowners in possession of the mineral rights to their property stand to gain financial rewards from drilling; those who don't own mineral rights may only experience the inconveniences associated with gas drilling. In addition, landowners in possession of mineral rights may receive different lease terms (based on a variety of factors) – creating another source of strain between neighbors.

This uneven distribution of benefits and costs has the potential to increase tension in communities, in some cases pitting neighbor against neighbor. In Mount Pleasant, Pa., disagreements over whether or not to drill in a community has led to angry letters, arguments and a sense of mistrust between neighbors.[477] Surveys of residents and community leaders in Pennsylvania's Marcellus region indicate that this division between "haves and have-nots" has occurred in a variety of communities.[478]

In New York State, landowners debate the pros and cons of natural gas drilling, with some who oppose drilling receiving letters that they describe as threatening.[479] In Southlake, Texas, home to the Barnett shale play, drilling opponents have received similar threatening letters.[480] Academic research reflects these anecdotes, showing that an uneven distribution of benefits and costs resulting from energy development can increase divisions in a community.[481]

These divisions have the potential to sour friendships, community groups and other social organizations important to any community. In some cases, disputes over drilling have led to lengthy and costly lawsuits, hardening the divisions. These lawsuits are sometimes between neighbors; in other cases, lawsuits arise between local communities and drilling companies.[482]

Landowner coalitions

Shale gas exploration has also united communities in some areas. In communities where leasing activity has begun, neighbors frequently join together to form landowner coalitions. These coalitions, which negotiate lease terms on behalf of their members, have the potential to result in better monetary outcomes, improved property rights protection and stronger environmental safeguards for landowners. These coalitions can also foster a sense of community among neighbors.

Examples of these coalitions include groups in Louisiana's Haynesville shale region, Pennsylvania and New York's Marcellus shale regions, Ohio's Utica shale region and Texas' Barnett shale region.[483]

Quality of life

The economic, social and environmental impacts discussed in other sections of this report can also affect natural amenities and quality of life for residents. Natural amenities include things like a quiet place to come home to, pristine views of surrounding land, and other factors that allow individuals to enjoy their community's natural surroundings. The impacts of increased traffic, noise, light and other aspects of industrial activity can be particularly jarring in a rural community. Research and reports from a variety of drilling locations describe some of these concerns over the past several years.

In parts of northern Pennsylvania, a dramatic increase in heavy truck traffic has diminished local residents' sense of their communities' rural character, and placed a burden on local

[477] Koenig, 2011.
[478] Laughner, 2012.
[479] Applebome, Oct. 2011; Banerjee, 2012.
[480] Gibbs, 2011.
[481] Brookshire and D'Arge, 1980; Little, 1976-77; Summers and Branch, 1984.
[482] Koenig, 2011; Mazzone, 2011; Primm, interview, 2011.
[483] Dickers, 2012; Integra Realty, 2011; Kallenberg, 2011; Jacquet, 2009.

governments to maintain roads.[484] In south Texas' Eagle Ford shale region, increased traffic has also impacted a largely rural community, slowing commutes and adding noise to a previously quiet region.[485] Local governments in southern New York State are bracing for increased traffic issues if the state decides to lift its moratorium on natural gas drilling.[486]

Natural gas drilling can also impact the visual quality of a region. Nighttime flares from newly drilled wells illuminate the skies of Bradford County, Pa., to the extent that "you don't need a nightlight."[487] In West Virginia's Marcellus shale region, residents have complained about visual impacts including light from gas flaring, the presence of large trucks on rural roads, and the sight of drilling rigs in rural areas (see section 6.G, *Visual impacts* for more details).[488]

Natural gas drilling also has the potential to impact natural amenities by increasing noise in and around a well site (see section 6.F, *Noise impacts* for more details).

On the other hand, the visual and noise impacts associated with natural gas drilling can be short-term, lasting only two to three months per well.[489] Once construction, drilling and fracturing have been completed, the visual and noise impacts from a well are minimal.

Some rural communities have cited natural gas development as a way to sustain a rural way of life. In southwestern Pennsylvania, farmers have leased their mineral rights and used the income to upgrade their equipment, make capital improvements, and supplement their annual income.[490] In Ohio, leasing around the Utica shale formation has similarly allowed farmers to sustain their operations.[491]

Longtime residents of communities affected by energy development projects sometimes perceive changes to the community very differently than newcomers who arrive to work in the industry. A variety of researchers have explored the old timer versus newcomer issue in energy development communities, focusing primarily on rural areas in the American West. In some areas, longtime community residents oppose oil and gas projects because energy development can disrupt the rural way of life and established social patterns.[492] Relative newcomers who relocated to a rural area for the peace and quiet may also oppose new energy projects out of fear that new development will destroy the very qualities that attracted them.[493]

In some parts of rural Colorado, oil and gas workers have said that local townspeople don't appreciate their presence and that they feel unwelcome.[494] In parts of Pennsylvania or Texas

[484] Blevins interview, 2012; Braiser and Filteau, 2011; Christopherson, 2010; Herr, 2011; Jacquet, 2009.
[485] Daugherty, 2011.
[486] Reilly, 2011; Sullivan County, 2009.
[487] Long, 2010.
[488] Maskell, 2011.
[489] NYSDEC, 2011.
[490] Haggerty, 2010; Kelsey et al., 2012; Koenig, 2011.
[491] Vega et al, 2011.
[492] Little, 1976-77; Massey, 1980; Smith and Krannich, 2000.
[493] Graber, 1974. Starrs and Wright, 1995.
[494] Chakrabarty, 2007.

where spills or other negative impacts have occurred, local residents sometimes perceive gas companies as an enemy of their community.[495]

On the other hand, recent news reports from Ohio describe excellent relationships between gas workers and the local businesses and restaurants that seek to attract their business.[496] Community leaders and local government officials in southwestern Pennsylvania tend to describe the gas companies as "good neighbors" who have an interest in positive community relations.[497]

In some cases, energy development projects in rural areas have led to increased mental health problems among community residents.[498] As energy development projects have transformed their community and social networks, some longtime residents struggle to cope and form the same types of "small-town" bonds that are extremely valuable. This stress has led residents in some energy boomtowns to seek mental health counseling services.[499]

Implications for North Carolina

Many of the quality of life and natural amenity issues examined in the research and reporting described above occurred in extremely rural areas. North Carolina's Deep and Dan River shale regions are significantly more populated than the western regions described in much academic research and some reporting. As a result, many of the issues arising in the old timer versus newcomer scenarios may be less applicable to the Deep and Dan River regions. Although some parts of the Triassic Basin (particularly the Wadesboro sub-basin and parts of the Dan River basin) are sparsely populated, none of the region's counties are as rural as the areas of Colorado, North Dakota, or Wyoming that were the subject of sociological research in previous decades.

Additionally, North Carolina's gas producing regions may not attract the same scale of industrial activity experienced in parts of the Marcellus, Eagle Ford, or Bakken shale formations. Less drilling activity would mean fewer newcomers and fewer visual, noise, and traffic impacts, mitigating the some of the community impacts described above. To give a sense of scale, Bradford County, Pa., currently has 1,935 Marcellus wells permitted.[500] The N.C. Geological Survey has estimated, very roughly, that the Deep River basin could warrant up to 368 gas wells.[501]

The prospect of natural gas production has the potential to divide North Carolina residents just as it has in other parts of the country. Landowners who control their mineral estates may be more likely to support drilling in the shale gas regions, as they are more likely to profit if drilling were to occur. However, confusion over who controls the mineral estates on a number of

[495] Blevins interview, 2012; Heinkel-Wolfe and Brown, 2011; McCoy and Tanfani, 2011.
[496] Smith, R., 2011.
[497] Andree interview, 2011; Coonley interview, 2011; Primm interview, 2011; Roth interview, 2011.
[498] Bacigalupi and Freudenberg, 1983; Kassover and McKeown, 1981; Little, 1976-77; Massey, 1980.
[499] Freudenberg, 1983; Freudenberg, 1986.
[500] MarcellusGas.org website, Jan. 3, 2012.
[501] Interviews with Dr. Jim Simons and Dr. Kenneth Taylor, 2011.

properties in Lee County may indicate some of the challenges associated with natural gas drilling in parts of North Carolina that have limited experience with extractive industries.[502]

Conflicts between neighbors also have the potential to occur in North Carolina. Since North Carolina is not as sparsely populated as Wyoming, Colorado or North Dakota, residents are more likely to be impacted by the decisions and actions of their neighbors. Community divisions surrounding natural gas drilling in more densely populated parts of Texas and Pennsylvania demonstrate some of the conflicts that could arise in North Carolina communities.[503]

However, one issue has arisen as a common concern for communities where new shale gas operations have begun: traffic. News reports, local officials and researchers in gas drilling regions have all reported significant increases in traffic volumes, especially large trucks, associated with new natural gas operations.[504] Increased traffic has the potential increase commute times and to frustrate local drivers, especially in rural communities unaccustomed to heavy traffic. For more details on potential traffic impacts, see section 3.B (infrastructure impacts).

[502] Murawski, Nov. 2011.
[503] Gibbs, 2011; Koenig, 2011.
[504] Brasier interview, 2012; Collette, 2011; Chakrabarty, 2007; Christopherson, 2011; Daugherty, 2011; Ellis, Oct. 2011; Heinkel-Wolfe and Brown, 2011; Herr, 2011; Jacquet, 2009; Primm interview, 2011.

Section 7 – Proposed Regulatory Framework

A. Guidance for a regulatory framework

Federal regulation

A number of federal environmental statutes apply to oil and gas production activities. Both Congress and the U.S. Environmental Protection Agency (EPA), however, have taken actions to exempt certain activities associated with oil and gas development from federal environmental standards – leaving significant areas of oil and gas regulation to the states.

The **Comprehensive Environmental Response Compensation and Liability Act (CERCLA or the "Superfund" Act)**[505] sets the ground rules for cleanup of sites with environmental contamination. Congress has excluded oil and gas products from the provisions of CERCLA,[506] leaving states to address financial responsibility and liability for contamination caused by oil and gas products.

Subtitle C of the Resource Conservation and Recovery Act (RCRA)[507] addresses hazardous waste. Often described as a "cradle to grave" permitting program, Subtitle C regulates hazardous waste from the point of generation of waste to its disposal.[508] In response to a direction from Congress to study the appropriate regulation of oil and gas wastes, EPA decided in 1988 to exempt waste associated with the oil and gas industry from regulation under Subtitle C.[509] EPA found that wastes produced in oil and gas production can include toxic substances and some have the characteristics of hazardous waste regulated under Subtitle C. EPA concluded, however, that RCRA regulation of these wastes would be too inflexible and too costly. Instead of regulating these wastes under Subtitle C of RCRA, EPA proposed to take other steps to improve management of oil and gas wastes:

1. Improve existing federal regulatory programs under the Clean Water Act, Safe Drinking Water Act and Subtitle D of RCRA (standards for disposal of non-hazardous solid waste);
2. Work with states to improve state-level waste management rules tailored to the oil and gas industry.
3. Work with Congress to develop any additional federal statutory authority needed (such as authority to address treatment and transportation of wastes regulated under Subtitle D of RCRA).

[505] 42 U.S.C. Chapter 103
[506] 42 U.S.C. Chapter 103, Section 9601
[507] 42 U.S.C. §6901 et seq. (1976)
[508] 42 U.S.C. Chapter 82
[509] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 FR 25447, July 6, 1988.

The exemption from federal hazardous waste regulation applies to wastes directly associated with oil and gas exploration development[510] including:

- Produced water
- Drilling fluids
- Drill cuttings
- Rigwash
- Well completion, treatment and stimulation fluids
- Pit sludges and contaminated bottoms from storage or disposal of exempt waste
- Pigging wastes from gathering lines
- Pipe scale

Because of the federal exemption, North Carolina will not be able to apply existing state hazardous waste rules to the storage, transportation and disposal of wastes generated in natural gas production even if those wastes would otherwise be considered hazardous wastes. The existing state rules only apply to wastes regulated under Subtitle C of RCRA.

Subtitle D of RCRA (standards for solid waste disposal) applies to disposal of drilling wastes. Given the exemption from Subtitle C, wastes that may be toxic or have other characteristics of hazardous wastes now fall under Subtitle D. In the 1988 decision to exempt drilling wastes from Subtitle C, EPA noted that:

> "The existing Federal standards under Subtitle D of RCRA provide general environmental performance standards for disposal of solid wastes, including oil, gas, and geothermal wastes, but these standards do not fully address the specific concerns posed by oil and gas wastes."[511]

In particular, EPA noted the lack of appropriate standards in Subtitle D for storage and transportation of these wastes.

Hazardous Materials Transportation Act.[512] The Hazardous Materials Transportation Act regulates the transport of hazardous chemicals to be added to fracturing fluids. The Act would not apply to wastes that fall under the RCRA exemption.

Safe Drinking Water Act.[513] The Safe Drinking Water Act sets national drinking water standards, but also regulates the underground injection of waste. The Underground Injection Control (UIC) program sets standards designed to prevent underground injection of waste from

[510] The exemption does not cover wastes from materials used in natural gas development, but not specific to the industry – such as painting waste, lubrication oils, compressor oil, used hydraulic fluids, waste solvents and pesticide wastes.
[511] Regulatory Determination for Oil and Gas and Geothermal Wastes, 53 FR 25446.
[512] 49 U.S.C. §5101 et seq. (1975)
[513] *42 U.S.C. §300f et seq. (1974)*

contaminating underground sources of drinking water. Federal UIC rules establish several different classifications for injection wells and set standards for each class. Class II wells can be used for underground injection of brines and other fluids associated with oil and gas production.

The 2005 Energy Policy Act (P.L.1090-58, August 2005) specifically exempted injection of fluids for hydraulic fracturing from regulation under the UIC provisions of the Safe Drinking Water Act that address underground storage or injection of fluids. The UIC program continues to apply to underground injection of waste from oil and gas production.

Clean Water Act. [514] Under the federal Clean Water Act, it is illegal to discharge waste from a point source (such as a pipe or ditch) to navigable waters[515] without a National Pollutant Discharge Elimination System (NPDES) permit. NPDES permits issued for industrial discharges and wastewater treatment plants include specific limits on individual pollutants. EPA has adopted guidelines for industrial discharges associated with oil and gas production, including discharges associated with shale gas extraction.[516]

NPDES permitting requirements also cover municipal and industrial stormwater discharges and stormwater runoff associated with construction. (The construction stormwater permit requires sedimentation control measures to prevent sedimentation pollution and high levels of turbidity in streams.) The 1987 Clean Water Act amendments that directed EPA to address stormwater discharges, however, specifically prohibited EPA from regulating stormwater from oil and gas exploration, development, production and treatment activities as long as the stormwater had not been in contact with raw materials, product (intermediate or finished) or waste.

EPA interpreted the 1987 exemption to apply to uncontaminated stormwater runoff from drilling sites, but continued to require an NPDES stormwater permit for construction-related activities such as building access roads and drill pads. The Energy Policy Act of 2005 overrode EPA's interpretation, adopting a more expansive definition of excluded mining, oil and gas activities. As a result, activities in preparation for drilling and movement of drilling equipment, including road construction, are now exempt from federal construction stormwater regulations addressing sedimentation pollution.

Clean Air Act.[517] In 1985, EPA set new source performance standards for emissions of volatile organic compounds (VOCs) and sulfur dioxide from natural gas processing facilities. EPA only recently proposed new source performance standards for other oil and natural gas operations. On Aug. 23, 2011, EPA proposed new source performance standards for emissions of VOCs and sulfur dioxide from a broader range of oil and natural gas exploration and production activities. As proposed, the standards would include operational requirements for completion of hydraulically fractured natural gas wells. EPA originally proposed to adopt a final NSPS rule by Feb. 28, 2012, but extension of the original comment period has delayed action beyond that

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[514] 33 U.S.C. § 1251, et seq

[515] The Clean Water Act defines "navigable waters" very broadly defined; the NPDES permitting requirement covers most rivers, lakes, streams and wetlands nationwide.

[516] 40 CFR Part 435, Subpart C.

[517] 42 U.S.C. §7401 et seq. (1970).

date. Until the proposed rules go into effect, no federal new source performance standards apply to emissions from many activities involved in production of natural gas, including hydraulic fracturing.

On June 17, 1999, the EPA adopted standards for the emission of hazardous air pollutants for certain sources associated with oil and natural gas production and natural gas transmission and storage. Under Section 112 of the Clean Air Act, EPA adopts Maximum Achievable Control Technology (MACT) standards for emissions of hazardous air pollutants by major sources. The Oil and Natural Gas Production MACT standard addressed emissions from glycol dehydration process vents, storage vessels and natural gas processing plant equipment leaks. The Natural Gas Transmission and Storage MACT standard addressed only glycol dehydration process vents. The Aug. 23, 2011, rulemaking notice for new source performance standards also proposed modifications to the MACT standards for these major source categories.

On Jan. 3, 2007, EPA adopted standards for the Oil and Natural Gas Production area source category. Area source standards address an aggregation of smaller sources and are based on generally available control technology. The existing area source standard for oil and natural gas production areas addresses benzene emissions from production areas located near urban areas. No changes have been proposed to the area source standard.

Summary

Since oil and gas exploration and production activities have been exempted from several federal environmental laws, many activities are regulated only at the state level. Storage and disposal of oil and gas wastes have been exempted from federal hazardous waste regulation, specifically to allow states to develop tailored programs for management of those wastes. Land application of wastewater is generally a matter for state rather than federal regulation. Although underground injection of wastewater produced from hydraulic fracturing continues to be subject to the Underground Injection Control provisions of the federal Safe Drinking Water Act, the actual injection of fluids for purposes of fracturing shale has been exempted from those provisions. Congress has also deferred to the states to regulate stormwater runoff from drilling sites, exempting those sites from Clean Water Act permitting requirements for construction stormwater and industrial stormwater discharges.

B. STRONGER guidelines for state oil and gas programs

EPA's 1988 decision not to regulate waste from oil and gas production activities under RCRA Subtitle C noted the need to strengthen state regulatory programs and fill gaps in other federal programs to adequately address drilling wastes. In 1990, EPA and the Interstate Oil Compact Commission (IOCC, now called the Interstate Oil and Gas Compact Commission, or IOGCC) jointly published a Study of State Regulation of Oil and Gas Exploration and Production Waste that included guidelines for the regulation of oil and gas exploration and production wastes by the IOCC member states (the "1990 Guidelines"). The published guidelines, developed by state, environmental and industry stakeholders, provided the basis for the State Review Program, a multi-stakeholder review of state exploration and production (E&P) waste management programs against the guidelines. In 1999, administration of the State Review Program devolved to a nonprofit organization called State Review of Oil and Natural Gas Environmental Regulations Inc. (STRONGER).

The Guidelines have been revised and expanded several times and in 2009 STRONGER formed a Hydraulic Fracturing Workgroup to develop specific guidelines for state regulation of hydraulic fracturing. In 2010, STRONGER distributed the workgroup's guidelines (the "2010 Hydraulic Fracturing Guidelines") for state regulation of hydraulic fracturing. The guidelines tend to be broadly worded – identifying regulatory issues that should be addressed without recommending specific standards. Among the recommended regulatory program elements:

- Standards for casing and cementing sufficient to handle highly pressurized injection of fluids into a well for purposes of fracturing bedrock and extracting gas.
- Identification of potential conduits for fluid migration; address management of the extent of fracturing; and identify actions to be taken in response to operational or mechanical problems.
- Standards for dikes, pits and tanks, including contingency planning and spill risk management procedures.
- Waste characterization, including testing of fracturing fluids. Waste should be tracked to ensure appropriate disposal.
- Prior notification of fracturing activity.
- Assessment of water supply for hydraulic fracturing in terms of volume in light of water supply, competing water uses and the environmental impacts of withdrawing water for fracturing. Use of alternative water sources and recycling of water should be encouraged.

In 2011, DENR invited STRONGER to assess North Carolina's existing regulatory structure against the STRONGER guidelines. The final STRONGER report on North Carolina was released on Feb. 28, 2012. [518] (The full report can be found in Appendix E: STRONGER Report.) The report identifies a number of gaps in the state's existing regulatory programs and makes three broad recommendations:

1. Develop formal standards for natural gas exploration and development

The review team found few environmental standards in place that expressly addressed oil and gas exploration and development. STRONGER expressed concern that attempting to apply general environmental standards to natural gas production on a case-by-case basis would be difficult if the volume of activity increased significantly. The report also notes that the potential operator, the public and state regulators all need to know with some certainty what the regulatory expectations are before starting into a permitting process. As a result, the STRONGER review team recommended that the state develop formal standards and technical criteria specifically for the industry based on STRONGER guidelines.

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[518] North Carolina State Report, STRONGER Inc., February 2012

2. Develop technical criteria for oil and gas activity

North Carolina's environmental programs have not focused on regulating the impacts of oil and gas development because there has not been an active industry in the state. If natural gas development comes to the state, North Carolina will need technical criteria to address oil and gas related activities including administrative criteria and technical criteria related to waste management, stormwater, abandoned sites, naturally occurring radioactive materials and hydraulic fracturing. If the state develops an oil and gas regulatory program, the review team recommended use of the STRONGER Guidelines and a review of programs in other states to develop those technical criteria.

3. Use stakeholder groups to develop an oil and gas program

The report notes that the Department of Environment and Natural Resources generally involves stakeholder groups early in discussions of proposed rules that involve major policy changes or are the subject of significant public interest. If North Carolina develops an oil and gas regulatory program, the review team recommended that the Department of Environment and Natural Resources continue to use independent scientific advisory groups, local advisory committees, groups of government, public and industry representatives, or other similar mechanisms, to obtain input and feedback in the development of the program.

C. State regulatory programs

DENR has looked at the environmental standards applied to hydraulic fracturing in a number of oil and gas-producing states. It is not possible to create a simple matrix of state environmental standards for hydraulic fracturing because of the complexity of the individual state programs. To find all of the environmental regulations that apply in any state, it is necessary to look beyond rules implemented by an oil and gas permitting agency. Standards that play a significant role in managing the impacts of hydraulic fracturing can often be found in water quality, air quality and waste management rules. Regulations dealing with water use – such as permitting requirements for water withdrawals – are also generally found outside the oil and gas regulatory program, but can be critical approvals needed for hydraulic fracturing.

This report describes the types of regulations common to most (if not all) programs in the oil and gas-producing states and then focuses on three representative state regulatory programs (Oklahoma, Texas and Pennsylvania).[519] Although other water quality and air quality rules may apply, this section will focus on standards specific to natural gas exploration and development and water use regulations applicable to hydraulic fracturing. The state by state summaries should not be taken as a complete picture of the regulatory program in each state; the difficulty of navigating through any state's statutes and rules to find all of the provisions potentially applicable to oil and gas production made that impossible. Instead, these are only intended as a snapshot of some of the regulations frequently applied to these activities.

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[519] Thirty states are members of the Interstate Oil and Gas Compact Commission.

Technical standards common to oil and gas states

Although the standards and methods of enforcement vary from state to state, most of the oil and gas-producing states have adopted technical standards for waste and chemical storage, waste disposal, well closure, blow-out prevention and site restoration. Examples include:

- Design standards for pits to contain brine and other fluids:
- Standards for discharge of tophole or pit water, including standards for land application.
- Disposal of drill cuttings (in pits or by land application)
- Standards for land application of residual waste (including contaminated drill cuttings)
- Requirements for containment around storage tanks
- Standards for well closure and for site restoration after completion of drilling
- Installation of safety devices (such as blow-out preventers)
- Monitoring of inactive wells
- Standards for underground gas storage
- Standards for underground injection of drilling wastes

Oklahoma

Since Oklahoma has had an oil and gas industry for many decades, the standards for hydraulic fracturing represent a combination of general standards for oil and gas development and more recent provisions to specifically address high pressure fracturing and horizontal drilling. Well permits for hydraulic fracturing are issued by the Oklahoma Corporation Commission, Oil and Gas Conservation Division (OCC). Rules applicable to natural gas exploration and development include:

Identification of Chemicals Used in Fracturing. The OCC has the authority to obtain information on chemical constituents used in hydraulic fracturing fluids from operators, service companies or other persons. The OCC has exercised the authority of this rule in the past to obtain information on the constituents of drilling fluids in the course of investigating a blowout or other release. Under the Federal Emergency Planning and Community Right-to-Know Act (EPCRA), 42 U.S.C.A Section 11043, health professionals may obtain information on chemical constituents of hydraulic fracturing fluids from the well owner or operator. The Oklahoma Hazardous Materials Emergency Response Commission (OHMERC) implements the requirements of EPCRA. Oklahoma has not required public disclosure of the constituents used in hydraulic fracturing.

Well Construction Standards. Oklahoma rules set very specific standards for well construction, casing and cementing. Oklahoma specifies the use of oil field grade steel casing for surface casing and other casing strings. The rules also set minimum footages for cement casing. The surface casing must extend at least 50 feet below the lowest layer of treatable groundwater; if the driller proposes to dispose of drilling fluids by annular injection, it must extend 200 feet below treatable groundwater.[520] Compliance with well construction standards must be verified by witnessing and testing, so the operator must provide 24-hour notice to the state agency before cementing surface casing or other casing strings to allow the agency to be on site. Oklahoma also requires the driller to submit reports on a number of steps in the casing and cementing process. [521]

Setbacks. The basic spacing for horizontal wells of 2,500 feet or more in depth is 330 feet from the property (or lease) line and 600 feet from another producing well. Special construction standards apply in wellhead protection areas and other sensitive sites. Oklahoma prohibits drilling or seismic activity related to drilling within 500 feet of the boundary of any Superfund site designated under the Comprehensive Environmental Response Compensation and Liability Act or any active hazardous waste treatment, storage or disposal facility.[522] Pits for storage of drilling waste cannot be located in a floodplain, a wellhead protection area or within one mile of a public water supply well if no wellhead protection area has been designated.

Management of Wastewater and Solid Wastes.[523] Oklahoma has created a category of "deleterious substances" that covers many drilling wastes that fall under the RCRA hazardous waste exemption, but require special handling. The term covers "any chemical, salt water, oil field brine, waste oil, waste emulsified oil, basic sediment, mud, or injurious substance produced or used in the drilling, development, production, transportation, refining, and processing of oil, gas and/or brine mining."[524]

Oklahoma rules allow disposal of drilling fluids by:

(A) Evaporation/dewatering and leveling of the reserve pit.

(B) Land application.

(C) Recycling.

(D) Commercial off-site earthen pit disposal.

(E) Annular injection (injection in the space between the surface casing and well bore).

(F) Hauling to a facility or location other than a commercial earthenpit.[525]

The application for a drilling permit must include information on the proposed method of disposal and Oklahoma rules include standards for each method. The rules set very specific construction and operation requirements for pits used to temporarily store or dispose of drilling fluids, including: liner specifications, freeboard requirements, secondary containment in areas subject to flooding, exclusion of stormwater runoff, vegetative stabilization to prevent

[520] Annular injection involves injection into the space between the surface casing and the borewall or between different strings of casing within a borehole.
[521] Oklahoma Administrative Code (OAC) 165:10-3-4, July 11, 2010.
[522] OAC 165:10-7-15, July 11, 2010.
[523] Oklahoma's rules for storage, transportation and disposal of drilling wastes are detailed and cannot be fully described here. This section can only provide a very broad overview.
[524] OAC 165:10-1-2, July 11, 2010.
[525] OAC 165:10-3-1(f), July 11, 2010.

erosion, and standards for pit closure. Pit bottoms must be separated by at least 25 feet from the groundwater. Pits cannot be located in a flood plain, wellhead protection area or within one mile of municipal water supply well if no wellhead protection area has been designated. [526]

Oklahoma also allows disposal of drilling fluids by underground injection or land application. A commercial disposal well operator must maintain a log that records the amount of waste received, the source and the operator and/or owner of the source of the waste. Oklahoma also has very detailed standards for land application of produced waters and other drilling fluids including: analysis for total suspended salts (or total dissolved solids), chlorides, pH, oil and grease; setbacks from property lines, streams and wells; and separation from the groundwater table.[527]

Trucks that haul "deleterious substances," (including certain drilling wastes) must be licensed by the Transportation Division of the OCC. The haulers are required to maintain run tickets stating the amount and origin of the substance hauled.

Water Use. The Oklahoma Water Resources Board issues permits for the use of surface and groundwater. Household uses are exempt from the permitting requirement. Before a permit can be issued for a surface water withdrawal, four conditions must be satisfied:

- The requested amount of unappropriated water must be available.
- A present or future need for the water must exist and the intended use must be beneficial.
- The use of water must not interfere with domestic or existing appropriative uses.
- The use must not interfere with existing or proposed beneficial uses within the stream system, and the needs of the area's water users if the application is for the transportation of water for use outside the area where the water originates.

Groundwater use also requires a permit. Normally, the applicant must publish notice of the application in a newspaper in the county where the well is to be located and give notice by certified mail to landowners within a quarter mile of the proposed well location. The OWRB typically issues a temporary provisional permit for water use in oil and gas operations including hydraulic fracturing. Impacts on competing water uses are considered in the permitting process.

Pennsylvania

Since 2005, Pennsylvania has experienced a boom in shale gas production by hydraulic fracturing. In response to specific problems experienced as a result of hydraulic fracturing, Pennsylvania has amended both state laws and rules in the last three years. The most recent state legislation[528] made changes in a number of regulatory requirements and authorized local governments to charge impact fees to recover the costs of maintenance and repair to local

[526] OAC 165:10-7-16, July 11, 2010.
[527] OAC 165:10-7-17, July 11, 2010.
[528] House Bill 1950, February 2012.

infrastructure (such as roads). Even now, the state's regulatory appears to provide less detailed standards than those found in either Oklahoma or Texas, particularly with respect to well construction and methods for casing and cementing the well. Pennsylvania does not require prior state approval of casing/cementing plans (although state rules set some basic standards) or emergency response plans. Pennsylvania also does not require notice to the regulatory agency before a well is drilled or hydraulically fractured.

Identification of Chemicals Used in Fracturing. Recent legislation requires operators to publicly disclose chemical constituents of fracturing fluids on FracFocus.[529]

Well Construction Standards. State rules require the driller to have a casing and cementing plan, but do not require prior approval of the plan by DEP in most cases. The rules require that the surface casing extend 50 feet below the lowest level of groundwater. Pennsylvania's casing and cementing standards are not as detailed as those adopted by Texas and Oklahoma. Pennsylvania does not require the driller to provide notice to the regulatory agency before cementing.

Setbacks. House Bill 1950 (enacted in February 2012)[530] made several changes to setback requirements for wells used in hydraulic fracturing:

- Property owners within 3,000 of a well permit must be notified of the new permit (previously 1,000 feet).
- New wells must be drilled at least 500 feet away from existing buildings or water wells (previously 200 feet), and if it's a supply point for public water supplies, the setback must be 1,000 feet.
- New wells must be drilled at least 300 feet away from streams, springs, water bodies or wetlands greater than one acre (previously 100 feet).

The bill also directs DEP to consider the impact of a proposed well on public resources including:

(1) Publicly owned parks, forests, game lands and wildlife areas.

(2) National or State scenic rivers.

(3) National natural landmarks.

(4) Habitats of rare and endangered flora and fauna and other critical communities.

(5) Historical and archaeological sites listed on the Federal or State list of historic places.

(6) Sources used for public drinking supplies in accordance with subsection (b).

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[529] FracFocus is a website maintained jointly by the Groundwater Protection Council and the Interstate Oil and Gas Compact Commission: www.fracfocus.com

[530] Act of Feb. 14, 2012, P.L. 87, No. 13 (amending Title 58 of Pennsylvania Consolidated Statutes), http://www.legis.state.pa.us/WU01/LI/LI/US/HTM/2012/0/0013..HTM

Management of Wastewater and Solid Waste. Before generating any waste, the operator must have a plan for the control and disposal of fluids, residual waste and drill cuttings, including tophole water, brines, drilling fluids, additives, drilling muds, stimulation fluids, well servicing fluids, oil, production fluids and drill cuttings from the drilling, alteration, production, plugging or other activity associated with oil and gas wells. The plan must be consistent with Pennsylvania laws (including water quality and solid waste statutes), but does not require prior state review and approval.

State rules set standards for use of pits and tanks for both temporary storage and disposal of drilling wastes. Open pits can be used for temporary storage as long as the operator maintains two-feet of freeboard. A pit or tank that contains drill cuttings from below the casing seat, “pollutional substances,” wastes or fluids other than tophole water, fresh water and uncontaminated drill cuttings must have a synthetic liner. DEP establish additional technical standards for permitting of pits and tanks, including a requirement that any pit maintain 20 inches of separation between the bottom of the pit and the groundwater table.

Unless authorized under the rules for temporary storage, use of a pit to store brine and other fluids produced during operation, service or plugging of a well requires a permit under the Clean Streams Law.[531] DEP rules set standards for siting and constructing pits (including setbacks from streams). Tophole water and pit water can also be land-applied as long as no additives, drilling muds, pollutional materials or drilling fluids other than gases or fresh water have been added to or are contained in the water (subject to exceptions approved by DEP). Drill cuttings from above the casing seat can be disposed of in a pit or by land-application on the drilling site as long as the drill cuttings are not contaminated with pollutional material, including brines, drilling muds, stimulation fluids, well servicing fluids, oil, production fluids or drilling fluids other than tophole water, fresh water or gases.

Contaminated drill cuttings and other residual wastes can also be disposed of on the drill site, but Pennsylvania has set more stringent standards for pits used in disposal of those wastes.

Water Use. Unlike the western oil and gas states, Pennsylvania lacks a statewide permitting program for water withdrawals. In parts of the state, water withdrawals require permits under rules adopted by the Susquehanna River Basin Commission. Some Pennsylvania counties that have experienced significant natural gas development (such as Bradford County) fall outside the jurisdiction of the Commission and have no water withdrawal permitting. After experiencing significant stream impacts as a result of large water withdrawals for hydraulic fracturing in low flow periods, DEP adopted rules requiring natural gas developers to submit a water management plan before the start of fracturing. There have been some questions about the legal effect of the plans, which are not permits and do not require notice to riparian property owners.

[531] 35 P. S. § § 691.1—691.1001

Texas

Like Oklahoma, Texas has a long history of oil and gas activity and the standards applied to hydraulic fracturing have grown out of a larger body of regulations applicable to oil and gas exploration and development generally. The Texas Railroad Commission has responsibility for permitting oil and gas activities.[532]

Identification of Chemicals Used in Fracturing. In 2011, Texas enacted legislation requiring operators to provide full public disclosure of the chemical composition of hydraulic fracturing fluids through the FracFocus website.

Well Construction Standards. The stated goal of the Texas rules is to ensure that "all usable-quality water zones be isolated and sealed off to effectively prevent contamination or harm, and all potentially productive zones be isolated and sealed off to prevent vertical migration of fluids or gases behind the casing."[533] The surface casing (a steel pipe encased in cement) must extend from the surface to a point below the deepest usable groundwater. Since the extent of the "usable water quality zone" determines how the casing and cementing standards apply, an applicant for a gas well permit needs a letter from the Texas Commission on Environmental Quality (TCEQ) that identifies the depth to which fresh water must be protected. The rules set out specific casing and cementing standards, protocols for testing cement strength and a requirement that the operator must submit a report on completion of the cementing to verify compliance. Unlike Oklahoma, Texas does not require prior notice that cementing will occur to allow a regulator to be onsite.

Setbacks. A well cannot be drilled nearer than 1,200 feet to any well completed in or drilling to the same horizon on the same tract or farm. Wells must also be located at least 467 feet from any property line, lease line or subdivision line. (The Railroad Commission can grant exceptions from both the well and boundary setbacks under certain circumstances.)

The Texas Railroad Commission has no rules establishing setbacks from residences, but local governments retain some authority to establish setbacks. A city may enact an ordinance regarding the proximity of an oil or gas well to homes or other structures within the city limits. An old law in the Texas Municipal Code, Section 253.005(c), also provides: "A well may not be drilled in the thickly settled part of the municipality or within 200 feet of a private residence." In counties with a population greater than 400,000 or a population greater than 140,000 and adjacent to a county with a population greater than 400,000, a residential developer can get Texas Railroad Commission approval of a subdivision plan that limits drilling activity to designated drill sites of at least two acres for every 80 acres in the subdivision (16 Texas Administrative Code (TAC) §3.76).

Management of Wastewater and Solid Wastes. Texas Railroad Commission rules set specific standards for storage and disposal of drilling wastes that have been exempted from regulation under the hazardous waste standards established under Subtitle C of the federal Resource

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[532] The Texas Railroad Commission website, http://www.rrc.state.tx.us/, provided much of the information on the Texas oil and gas program.

[533] Texas Administrative Code (TAC), Title 16 Part 1 Rule § 3.13 (a)(1).

Conservation and Recovery Act.) The state standards for storage and disposal of exempt drilling wastes can be found in Texas Administrative Code (TAC) Title 16, Chapter 3. The rules establish standards for construction and use of pits to store or dispose of wastes, including: saltwater disposal pits; emergency saltwater storage pits; collecting pits; skimming pits; brine pits; brine mining pits; drilling fluid storage pits (other than mud circulation pits); drilling fluid disposal pits (other than reserve pits or slush pits); washout pits; and gas plant evaporation/retention pits. A state permit is required for construction or use of a pit for storage/disposal of oil and gas wastes. The Texas Railroad Commission, in coordination with the U.S. Environmental Protection Agency, also issues permits for injection wells to be used for disposal of oil and gas wastes.

Oil and gas wastes taken off the drilling site for disposal must be hauled by a permitted hauler. The well operator is required to keep records identifying the hauler and the disposal site for any drilling wastes taken offsite for disposal. Those records must be maintained for three years.

Some drilling wastes can be disposed of without a permit. Freshwater condensate and inert materials (such as concrete, glass, wire and wood) can be disposed of without a permit so long as the materials are not deposited in surface waters. No permit is required to land-apply low chloride wastes (including drilling fluids with a chloride concentration of 3,000 milligrams per liter or less; drill cuttings, sands and silts produced by contact with low chloride drilling fluids; and pipe wash water) on the lease site by permission of the surface owner. Wastes with a higher concentration of chlorides can be dewatered and buried at the drill site without a permit.

Texas has also adopted specific standards for recycling of oil and gas waste[534] and for disposal of drilling wastes contaminated by naturally occurring radioactive materials[535].

Water Use. An operator proposing to withdraw water from a river, lake or stream must obtain a permit from the Texas Commission on Environmental Quality (TCEQ). A permit may be granted only if:

- The applicant makes beneficial use of water;
- Water is available and its use does not impair vested water rights
- The applicant practices water conservation
- The use of water is not detrimental to public welfare.

Texas groundwater belongs to the owner of the land above it and may be used or sold as private property. A landowner has a right to take for use or sale all of the water that can be captured from beneath the land. The Texas Water Code authorizes the creation of water conservation districts and groundwater management areas with the purpose of preserving, protecting and conserving groundwater resources. These entities can regulate well spacing and enjoin wasteful water practices. Districts can also require permits for new wells.

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[534] TAC Subtitle 16, Chapter 4, Subchapter B.
[535] TAC Subtitle 16, Chapter 4, Subchapter F.

D. Other sources of recommended standards

1. New York Supplemental Draft Generic Environmental Impact Statement

The state of New York has effectively had a moratorium on production of natural gas by hydraulic fracturing since December 2010 when outgoing Gov. David Paterson temporarily halted the practice by executive order. The New York Department of Environmental Conservation (N.Y. DEC) has prepared an environmental impact statement on the state oil, gas and mining program's ability to manage the impacts of hydraulic fracturing. N.Y. DEC issued a Revised Supplemental Draft Generic EIS in September 2011.[536] The 2011 Revised GEIS includes specific recommendations for new permitting standards to address hydraulic fracturing. The primary recommendations are described below.[537]

Identifying fracturing chemicals. The 2011 SGEIS identifies 322 chemicals proposed for use in New York and includes health hazard information for each category of chemicals as identified by the NYS Department of Health. Applicants must fully disclose to DEC all products and combinations used in the high-volume hydraulic fracturing process. In addition, applicants must agree to publicly identify the names of the additives, subject to exemptions where the applicant can prove that the exemption is necessary to protect confidential business information.

Prohibitions on drilling in certain areas to protect water supplies; drilling would not be allowed:

- Within 2,000 feet of public drinking water supply wells or reservoirs (this restriction will be reviewed in three years);
- On the state's 18 primary aquifers and within 500 feet of aquifer boundaries;
- Within 500 feet of a private water supply well or spring used for domestic water supply, unless waived by landowner;
- In the 100-year floodplain;
- On principal aquifers without site-specific reviews; or
- In the Syracuse and New York City watersheds. As the only unfiltered surface supplies of municipal water in the state, N.Y. DEC proposed to give these watersheds special protection. High-volume fracturing will be prohibited within the watersheds, within 4,000 feet of the watershed boundaries and within 1,000 feet of NYC's subsurface water supply infrastructure unless approval is granted after site-specific review.

N.Y. DEC estimated that more than 80 percent of the Marcellus Shale where gas extraction is viable would still be accessible for drilling under these recommendations.

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[536] New York Department of Environmental Conservation, Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program, September 2011, http://www.dec.ny.gov/energy/75370.html

[537] New York DEC, 2011 Recommendations for Permitting High Volume Hydraulic Fracturing, http://www.dec.ny.gov/energy/75664.html, viewed March 7, 2012.

Revised casing and cementing standards. The Revised Draft SGEIS recommended modifying the oil and gas program's existing casing standards to require a third, cemented well casing around each well to prevent the migration of gas. The three required casings are the surface casing, the new intermediate casing and the production casing. The depths of both surface and intermediate casings will be determined by site-specific conditions.

Spill control and wastewater management. New guidelines will require that flowback water stored on-site be placed in watertight tanks within a secondary containment. No open containment will be allowed. Secondary containment will also be required for all fracturing additive containers, additive staging areas and flowback tanks to ensure any spills of wastewater or chemicals at the well pad do not migrate into water supplies.

N.Y. DEC noted that many drilling companies have started to recycle much of the flowback water, greatly reducing the need for disposal. The agency has proposed additional oversight for wastewater disposal:

- Applicants must have a DEC-approved plan for disposing of flowback water and production brine.
- DEC would institute a process to monitor disposal of flowback water, production brine, drill cuttings and other drilling waste streams that is similar to the handling of medical waste.
- DEC will require full analysis and approval under existing state and federal water laws and regulations before a water treatment facility could accept flowback water. This would include a treatment capacity analysis for any publicly operated treatment works facility (POTW) and a contingency plan if the primary disposal for wastewater is a POTW.

Stormwater Control. N.Y. DEC has proposed to issue a new general stormwater permit requiring strict stormwater control measures to prevent stormwater from contaminating water resources.

Water Use. Until recently, the state of New York lacked a statewide water withdrawal permitting program. The parts of the state under the jurisdiction of either the Delaware River Basin Commission or the Susquehanna River Basin Commission had water withdrawal permitting under the authority of the commissions. In 2010, New York enacted a new Water Resource Act that now requires a state permit for areas outside the jurisdiction of the river basin commission. A special permit will be required to withdraw large volumes of water for industrial and commercial purposes to ensure there are not adverse impacts. Permits issued under the law will be subject to limits to prevent impacts upon ecosystems and other water quantity requirements. The permit applicant will be required to identify the proposed water source and file an annual report on the aggregate amount of water withdrawn or purchased.

Air Quality. Requires enhanced air pollution controls on engines used at well pads. DEC will monitor local and regional air quality at well pads and surrounding areas. To reduce greenhouse gas emissions, requires use of existing pipelines when available rather than flaring gas.

Conserving Habitat. N.Y. DEC will require compliance with best management practices for land-disturbing activity on private forestlands of 150 acres or more and on privately owned grass lands of 30 acres or more.

2. American Petroleum Institute guidance

The API has developed a set of standards, guidance documents, and recommended industry practices that address risk management associated with natural gas drilling and hydraulic fracturing. These five documents are:

- HF1 – Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines
- HF2 – Water Management Associated with Hydraulic Fracturing
- HF3 – Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing
- Std. 65, Part 2 – Isolating Potential Flow Zones During Well Construction
- RP 51R – Environmental Protection for Onshore Oil and Gas Production Operations and Leases

The first guidance document provides useful technical guidance on well construction and integrity standards for wells to be hydraulically fractured.[538] The guidance addresses well design, cementing, casing, well logging and monitoring/testing requirements for steps in the well construction and fracturing process. The guidance often refers to previously adopted API standards generally applicable to the oil and gas industry, such as cement and casing specifications.

API's guidance on water management addresses both water sources for hydraulic fracturing and methods for disposing of waste waters.[539] The guidance document notes the importance of planning for surface water and groundwater withdrawals to avoid impacts to natural resources and to other water users. The guidance also identifies some innovative alternative sources of water, including cooling water discharges and inactive quarries.

API guidance documents generally focus on the technical aspects of gas production and hydraulic fracturing. API recognizes that state standards will vary even on relatively technical issues, such as casing and cementing standards, because of varying geologic and hydrologic conditions. The guidance documents are written as best management practice recommendations for use by the industry in the context of federal, state and local regulations. API guidance documents for hydraulic fracturing do not appear to address siting standards (such as setbacks and buffer requirements) or technical waste management, water quality and waste management standards.

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[538] American Petroleum Institute, Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines, API Guidance Document HF 1, First Edition, October 2009.

[539] American Petroleum Institute, Water Management Associated with Hydraulic Fracturing, API Guidance Document HF2, First Edition (2010).

Some of the more general lessons taken from the API guidance on well construction:

- The quality of a cementing job and the integrity of a well casing can only be assured by review of supporting data collected as the well is constructed and tested. For cementing, the necessary information would include drilling reports, drilling fluid reports, cement design and related laboratory reports, open-hole logs and other information. API also recommends testing the effectiveness of a cement seal by using various hydraulic pressure tests to ensure well integrity.[540]
- Surface casing must be set at a depth adequate to protect groundwater supplies. State rules set the minimum depth of surface casing and most states require the casing to be set below the deepest groundwater aquifer. At a minimum, API recommends surface casing be set at least 100 feet below the deepest underground drinking water supply encountered while drilling the well. Surface casing should be cemented from bottom to top, completely isolating groundwater aquifers. [541]
- After selecting the well site and before drilling, API recommends that the driller take baseline water quality samples from nearby water sources and have the samples analyzed based on "applicable regulatory requirements." (Presumably this refers to state water quality standards and established sampling and testing protocols.) API recommends that baseline testing should include rivers, creeks, lakes, ponds and water supply wells within an area based on the anticipated fracture length plus a safety factor. The purpose of collecting pre-drilling water quality data is to allow the operator to determine whether later water quality changes resulted from gas production. [542]

3. Report of the Secretary of Energy's Advisory Board, Shale Gas Production Subcommittee

In March 2011, the President charged the Secretary of Energy's Advisory Board to recommend measures to improve the safety and environmental performance of hydraulic fracturing. The Board's Shale Gas Subcommittee issued an initial 90-day report in August 2011 that made 20 recommendations, but did not set priorities or discuss implementation. A final report, issued Nov. 18, 2011, provided more detail on implementation of the recommendations by state and federal agencies.[543] Recommendations for federal action included:

- EPA should act to reduce emissions of air pollutants, including ozone precursors and methane
- Require disclosure of hydraulic fracturing fluid composition
- Eliminate use of diesel fuel in fracturing fluids[544]

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[540] Ibid, Section 6.4, page 10.
[541] Ibid, Section 7.3, page 11.
[542] Ibid, Section 10.2, page 20.
[543] Secretary of Energy Advisory Board, Shale Gas Production Subcommittee Second Ninety Day Report, November 18, 2011, http://www.shalegas.energy.gov/resources/111011_90_day_report.pdf
[544] Ibid, pg.4

- The subcommittee also identified actions to be taken by state oil and gas programs:
- Measure and report makeup of process water and flow throughout the fracturing and cleanup process; track all transfers of process water.
- Adopt best practices for well construction, including casing, cementing and pressure management standards.
- Require background water quality testing to document conditions in water supply wells and surface waters prior to drilling.

4. Guidance under development

Several public and private agencies are developing guidelines for hydraulic fracturing. The Department of Interior's Bureau of Land Management is drafting rules for hydraulic fracturing on public lands. The draft rules have not yet been published in the Federal Register for comment; according to various news accounts and industry sources, a leaked copy of the draft rules included a requirement for disclosure of chemicals used in fracturing.

The U.S. Environmental Protection Agency started a study of the impacts of hydraulic fracturing on drinking water in 2011. The plan of study, released in November 2011, identifies five fundamental questions to be addressed in the study:

- Water Acquisition: What are the potential impacts of large volume water withdrawals from ground and surface waters on drinking water resources?
- Chemical Mixing: What are the possible impacts of surface spills on or near well pads of hydraulic fracturing fluids on drinking water resources?
- Well Injection: What are the possible impacts of the injection and fracturing process on drinking water resources?
- Flowback and Produced Water: What are the possible impacts of surface spills on or near well pads of flowback and produced water on drinking water resources?
- Wastewater Treatment and Waste Disposal: What are the possible impacts of inadequate treatment of hydraulic fracturing wastewaters on drinking water resources?[545]

The EPA study will be completed in 2014.

The Environmental Defense Fund is working with Southwestern Energy of Houston on a draft model regulatory framework for hydraulically fractured natural gas well. A working draft has been in limited circulation, but has not been officially released.

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[545] U.S.EPA, Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources, EPA/600/R-11/122/November 2011/www.epa.gov/research, November 2011.

E. State policies to guide decisions on hydraulic fracturing

A number of existing state environmental policies (reflected in both statutes and rules) could provide guidance for a regulatory program to address hydraulic fracturing for natural gas:

Groundwater should be protected and managed as a potential drinking water supply. Current statutes and rules reflect that policy direction in a number of ways. North Carolina has health-based groundwater standards and a stated goal of maintaining the quality necessary to allow use of groundwater resources for drinking water. The state's groundwater standards provide the baseline for many environmental permits – including permits for land application of waste. State law also restricts underground injection of waste as a measure to protect groundwater quality for future drinking water use.

Water supply planning is critical to maintaining an adequate water supply for industry, agriculture and drinking water needs. State law requires development of state and local water supply plans. After experiencing severe droughts affecting large areas of the state (including major municipalities) in 2002 and 2007, the General Assembly strengthened the water supply planning laws to require development of water shortage response plans meeting minimum state standards and increase collection of data on water use.[546] In 2010, the General Assembly enacted legislation requiring DENR to develop river basin hydrologic models as a tool for water supply planning.[547]

A person who causes groundwater contamination or other environmental degradation has the responsibility to assess and clean up the damage. Those responsibilities include providing an alternative water supply to anyone whose water supply well has been made unsafe for use. This is a principle applied through all of the state laws addressing environmental contamination. Activities that have a high potential for groundwater contamination in particular typically require financial assurance in the form of environmental insurance, a bond or other instrument to ensure that the operator will have sufficient resources to reclaim the site and cleanup any contamination. Those types of financial assurance requirements currently apply to landfill operators, mine operators, owners/operators of commercial petroleum underground storage tanks and operators of facilities handling hazardous waste.

F. Recommended regulatory framework

Statutory Framework and Organization. The State's Oil and Gas Conservation Act creates a basic framework for issuance of well permits and gives the Secretary of Environment and Natural Resources the authority to adopt rules.[548] The Act itself needs to be modernized; most of the provisions in the Act date back to 1945 and some would be incompatible with a modern natural gas regulatory program. For example, the bonding requirement covers only well closure at the end of production and does not address site reclamation or cleanup of environmental contamination. The statute also gives DENR the authority to cap oil or gas production based on

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[546] The Drought Response/ Water Management Act of 2008 (S.L. 2008-143)
[547] S.L. 2010-143
[548] N.C. General Statute 113-381, et seq.

in-state demand, which is clearly incompatible with the interstate gas market. It would be possible, however, to update the statute to provide the framework for a modern oil and gas program.

The STRONGER report noted that having the oil and gas permitting program in DENR has the advantage of allowing easier coordination of permit reviews. DENR agrees that maintaining the oil and gas permitting program in DENR would be the most efficient way to deliver an oil and gas permitting program given the ability to use the existing statutory framework and coordinate with the environmental programs in the department. The statute currently gives the Secretary of Environment and Natural Resources rulemaking authority under the Oil and Gas Conservation Act. Another alternative would be to transfer the rulemaking authority to one of the regulatory commissions organized under the department, such as the Mining Commission or the Environmental Management Commission, to take advantage of a broader range of viewpoints in the rulemaking process.

Development of regulations for natural gas exploration and development. In developing a regulatory framework for natural gas exploration and production, it is important to think about the full range of activities involved that extend beyond construction of the well and fracturing the shale. Gas production begins with activities similar to those associated with any development – site clearing, grading, construction of access roads. The impacts of those activities are familiar; many are already addressed by existing state regulations under the Sedimentation Pollution Control Act.

Significant gaps are found in existing state environmental standards with respect to many other activities required for natural gas production. As noted in the STRONGER report, North Carolina has not developed regulations for the oil and gas industry because the industry has not had a presence in the state. Existing water quality, air quality, waste management and water use standards were not developed with the natural gas production industry in mind; as a result, standards may be inadequate or, in some case, nonexistent. Although the state has well construction standards, for example, the standards were developed for water supply wells; those standards are inadequate for construction of wells that must withstand the high pressures of hydraulic fracturing.

Some state rules have been built on a foundation of federal requirements that do not apply to natural gas exploration and development activities. Natural gas exploration and production activities have been exempted from the Clean Water Act's construction stormwater permit requirement; underground injection control permitting under the Safe Drinking Water Act (for hydraulic fracturing); and federal hazardous waste regulations (as applied to oil and gas wastes). Since state rules implementing those federal programs are written to apply only to activities regulated under the federal statute, there are no applicable standards at the state level. In the area of waste management, in particular, existing state rules are inadequate to address the potential impacts of natural gas exploration and development. Unlike the oil and gas producing states, North Carolina has never considered the need for rules to manage transportation, storage and disposal of a waste stream has the characteristics of hazardous waste, but is exempt from regulation under RCRA.

STRONGER recommended development of environmental standards specific to activities associated with natural gas exploration and production to address those gaps and to provide greater consistency and predictability. DENR concurs in that recommendation. A comprehensive oil and gas regulatory program requires such a broad range of standards - many of them technical - that DENR cannot make specific recommendations on a full set of regulatory standards without further study. The STRONGER guidelines and a review of regulations in Oklahoma, Pennsylvania and Texas provide an outline of the types of standards needed:

- Standards for casing and cementing sufficient to handle highly pressurized injection of fluids into a well for purposes of fracturing bedrock and extracting gas.
- Siting standards for wells and other gas production infrastructure (such as storage pits and tanks), including any setbacks and prohibited areas.
- Identification of potential conduits for fluid migration; management of the extent of fracturing; and actions to be taken in response to operational or mechanical problems.
- Standards for dikes, pits and tanks, including contingency planning and spill risk management procedures.
- Waste characterization, including testing of fracturing fluids and tracking of waste to ensure appropriate disposal.
- Identification of allowed methods of disposal for both wastewater and solid waste from gas production and any necessary standards.
- Prior notification of cementing and fracturing activity.
- Assessment of water supply for hydraulic fracturing in terms of volume of water supply, competing water uses, and the environmental impacts of withdrawing water for fracturing. Use of alternative water sources and recycling of water should be encouraged.
- Well closure and site reclamation standards; post-closure monitoring.
- Safety equipment, including blowout preventers.
- Notice, record-keeping and reporting requirements.

With respect to these and other technical standards and compliance measures, DENR recommends adopting STRONGER's suggestion to develop oil and gas regulatory standards through a process that takes advantage of scientific/technical advisory groups and allows for broad public participation.

Data Management. DENR currently has no computer data management capabilities with respect to oil and gas regulatory activities. The STRONGER review noted this deficiency in North Carolina's programs. In order to effectively manage the large volumes of reporting information associated with baseline sampling, production, drilling logs, and hydraulic fracturing, North Carolina will need to make substantial investments in electronic databases and online reporting tools. A sound electronic data management system can benefit the interested public, the industry, and state regulatory agencies. For industry, a data management system with a strong public interface could make information collected by the N.C. Geological Survey more easily available for use in guiding future exploration and leasing decisions. If natural gas production comes to North Carolina, DENR would also expect a much greater demand from the public for information on leasing activities. Accurate and timely tracking of production activity also improves the state's ability to provide appropriate environmental oversight for drilling activity and collect revenue from severance taxes.

DENR is currently developing a database of groundwater data collected by a number of different programs in the department. This database, known as the Groundwater Decision Support System, could be used to manage reporting of baseline sampling of water supply wells as well as other groundwater and geological data reported to the state in association with oil or gas development. The current database development project would have to be expanded in order to fully develop these capabilities. Additionally, due to budget constraints, that database development project does not include a web interface where members of the public could query the database to stay informed about groundwater quality issues that might affect them.

Role of Local Government. If the state adopts rules for natural gas exploration and development, the General Assembly will need to clearly define the ongoing role of local governments in regulating these activities. At one end of the spectrum, the state could adopt a comprehensive state regulatory program and completely preempt local regulation. A number of states that have oil and gas regulatory programs, however, continue to allow local governments to exercise some authority with respect to siting. In these states, a common approach allows the local government to exercise local planning and zoning authority but prohibits the local government from completely excluding oil and gas development.

New York's Department of Environmental Control would actually require the applicant for a state oil and gas permit to certify that a proposed activity would be consistent with local land use and zoning laws.

In Texas, a city may enact an ordinance regarding the proximity of an oil or gas well to homes or other structures within the city limits. In counties with a population greater than 400,000 or a population greater than 140,000 and adjacent to a county with a population greater than 400,000, a residential developer can get Texas Railroad Commission approval of a subdivision plan that limits drilling activity to designated drill sites of at least two acres for every 80 acres in the subdivision.[549]

Pennsylvania has allowed local jurisdictions to maintain zoning/planning authority and the ability to control floodplain development, but under conditions that do not allow the local government to entirely exclude gas production.

Models exist in North Carolina law for striking a similar balance between a comprehensive state regulatory program and local government planning and zoning authority. For example, North Carolina has developed a comprehensive regulatory program for hazardous waste facilities, but allows local government to continue to exercise planning and zoning authority over those

[549] 16 Texas Administrative Code (TAC) §3.76.

facilities within limits set by state law. A local ordinance that generally applies to development in a city or county (such as a stormwater ordinance) is presumed to legitimately apply to hazardous waste facilities. But the statute expressly prohibits a city or county from adopting ordinances to exclude hazardous waste facilities. [550]

G. Conclusion

DENR can make immediate recommendations on some general standards and requirements for natural gas exploration and production. Some of these recommendations reflect an emerging consensus among state and federal regulators. Others address conditions specific to North Carolina and the need for additional information. DENR's initial recommendations for regulatory and legislative action can be found in the summary of recommendations at the end of this report.

The development of specific standards for gas production and hydraulic fracturing (such as siting criteria, waste management guidelines and well construction standards) will require a more detailed discussion of standards appropriate for North Carolina conditions. The process for developing those standards should include input from local governments, industry, technical experts, and the public.

[550] N.C. General Statute 130A-293.

Section 8 – Consumer protection and legal issues

This section has not yet been provided by the Department of Justice.

Section 9 – Recommendations and limitations

A. Recommendations

After reviewing other studies and experiences in oil and gas-producing states, DENR believes that hydraulic fracturing can be done safely as long as the right protections are in place. It will be important to have those measures in place before issuing permits for hydraulic fracturing in North Carolina's shale formations. A number of states have experienced problems associated with natural gas exploration and development because the appropriate measures were not in place from the beginning – forcing both the state and the industry to react after damage had already been done. DENR has identified a number of immediate recommendations for management of natural gas exploration and development activities. A complete oil and gas permitting program will require more detailed standards than it is possible to provide in this report and those standards should be based on conditions in North Carolina. Conditions in the Triassic Basins of North Carolina are not identical to those found in Pennsylvania or other gas-producing states. For example, we need to understand the depth of usable groundwater in the Triassic Basin in order to set well construction standards that will protect our drinking water resources.

Based on the research and analysis in this report, the Department of Environment and Natural Resources in consultation with the Department of Commerce developed the following recommendations for the General Assembly. It should be noted that these recommendations do not take into account information from the Department of Justice's section on consumer protection, because DENR had not received that section of the report in time for preparation of the recommendations. These recommendations also do not take into account public comments, which will be collected in before the report is finalized.

A brief description of each recommendation is listed, followed by a more detailed explanation of each recommendation below. The recommendations are not listed by priority.

21. **Collect baseline data including groundwater, surface water, and air.**
22. **Require oil and gas operators to prepare and have a DENR-approved Water Management Plan and limit water withdrawals to 20% of the 7Q10 stream flow.**
23. **Enhance existing oil and gas well construction standards to address the additional pressures of horizontal drilling and hydraulic fracturing.**
24. **Develop setback requirements and identify areas (such as floodplains) where oil and gas exploration and production activities should be prohibited.**
25. **Develop a state stormwater regulatory program for oil and gas drilling sites.**
26. **Develop specific standards for management of oil and gas wastes.**

27. **Require full disclosure of hydraulic fracturing chemicals and constituents to regulatory agencies. With the exception of trade secrets, require public disclosure of hydraulic fracturing chemicals and constituents.**
28. **Prohibit the use of diesel fuel in hydraulic fracturing fluids**
29. **Improve data management capabilities and develop an e-permitting program**
30. **Ensure that state agencies, local first responders and industry are prepared to respond to a well blowout, chemical spill or other emergency.**
31. **Develop a modern oil and gas regulatory program, taking into consideration the processes involved in hydraulic fracturing and horizontal drilling technologies, and long-term prevention of physical or economic waste in developing oil and gas resources.**
32. **Keep the environmental permitting program for oil and gas activities in DENR where it will benefit from the expertise of state geological staff and the ability to coordinate air, land and water quality permitting.**
33. **Develop a coordinated permitting process.**
34. **Address the distribution of revenues from oil and gas excise taxes and fees to support the oil and gas regulatory program, fund environmental initiatives, and support local governments impacted by the industry.**
35. **Identify a source of funding for repair of roads damaged by truck traffic and heavy equipment.**
36. **Clarify the extent of local government regulatory authority over oil and gas exploration and production activities.**
37. **Complete additional research on impacts to local governments and local infrastructure.**
38. **Complete additional research on potential economic impacts.**
39. **Address the natural gas industry's liability for environmental contamination caused by exploration and development, particularly for groundwater contamination.**
40. **Provide additional public participation opportunities**

1. **Collect baseline data including groundwater, surface water, and air.**

We recommend that:

a. The General Assembly require each oil and gas operator to obtain background groundwater quality data from existing water supply wells near the proposed drill site before drilling begins and to share this data with the regulatory agency. Each water supply well located within a distance determined by the horizontal extent of the hydraulically fractured well should be sampled and analyzed for dissolved methane, volatile and semi-volatile organic compounds, chloride, total dissolved solids, bromide, and dissolved metals.

b. DENR should collect pre-drilling surface water monitoring data for areas proposed for drilling to establish baseline water quality information. The extent and location of data collection should be determined as drilling blocks are established.

c. DENR should collect pre-drilling air emissions data for areas proposed for drilling, at a distance determined through additional research.

   Part of this additional research should involve evaluation of the existing state air toxics program and its ability to protect landowners who lease to oil and gas operators. North Carolina's air toxics program currently requires a source of state-regulated toxic air pollutants to demonstrate compliance with health-based pollution standards at the property boundary. The program has assumed that measuring toxic air pollutants at the boundary of an industrial facility adequately protects nearby residents who may have long-term exposure to the pollutants. Shale gas production often occurs under a lease of property that may be owned and in some cases occupied by another person. In that case, the property owner may be exposed to unhealthy concentrations of toxic pollutants associated with gas production. The existing air toxics program should be evaluated to determine whether it provides adequate protection when natural gas production occurs on residential properties or farms.

2. **Require oil and gas operators to prepare and have a DENR-approved Water Management Plan and limit water withdrawals to 20% of the 7Q10 stream flow.**

   - We recommend that the General Assembly require oil and gas operators to have a water management plan that has been approved by DENR for any new water withdrawals for use in hydraulic fracturing (similar to plans required by the Delaware and Susquehanna River Basin Commissions). Any new surface water withdrawals for gas well development should be limited such that the cumulative instantaneous withdrawals in the vicinity of the intake do not exceed 20 percent of the 7Q10 stream flow. Instantaneous withdrawals greater than 20 percent of the 7Q10 stream flow should require site-specific evaluation of potential impacts. The 7Q10 threshold has been used for many years to manage impacts to stream flows and has been shown to be protective of other water users and the environment. This approach would be naturally protective during low-flow conditions and droughts (which is particularly important in small watersheds); prevent excessive withdrawals during periods of peak usage; and prevent any surface water in North Carolina from drying up due to natural gas withdrawals.

     Because of their variability in the Triassic Basins, DENR cautions that groundwater resources may not be adequate to meet water needs for hydraulic fracturing operations.

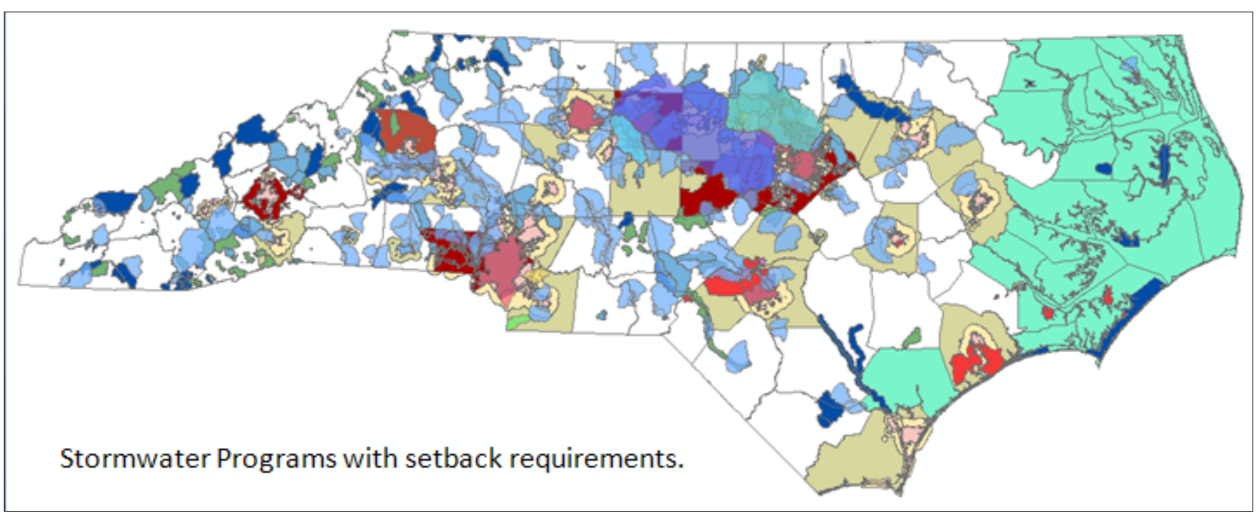
- We recommend that the gas industry and public water utilities work together to meet water needs for gas exploration while protecting water quality and the rights of other water users. We encourage the investigation of options to satisfy water needs by recycling to the extent practical and taking advantage of unused capacity at existing withdrawal facilities.

3. Enhance existing oil and gas well construction standards to address the additional pressures of horizontal drilling and hydraulic fracturing.

North Carolina's oil and gas well construction standards haven't changed over the last couple of decades. These should be revised, relying on the best guidance currently available, to develop well construction standards for oil and gas activities, including horizontal drilling and hydraulic fracturing.

4. Develop setback requirements and identify areas (such as floodplains) where oil and gas exploration and production activities should be prohibited.

Currently, no uniform setback requirements for oil and gas exploration or production activities exist in North Carolina. The state stormwater and Phase II stormwater programs require a 30-foot setback from streams and wetlands for any impervious surface. The water supply watershed protection program requires impervious surfaces to be located 30-feet away from perennial streams for low-density projects and 100-feet away from perennial streams for high-density projects. Riparian buffer protection rules are in place in the Neuse, Tar-Pamlico and Catawba River basins and the Jordan Lake and Randleman Lake watersheds that require 50-foot protected riparian buffers from streams, lakes and ponds. These existing setback and buffer requirements were designed to manage the impacts of conventional development activities and may not be sufficient for the infrastructure associated with oil and gas development.



Stormwater Programs with setback requirements.

Many other states have specific setback requirements in place or proposed for oil and gas exploration or production activities. Pennsylvania regulations require storage or disposal pits for production fluids to be located at least 100 feet away from a stream, wetland or body of water. Land application areas, drill cutting disposal areas and residual waste pits must be at least 200 feet from a water supply and 100 feet away from a stream, wetland or other body of water. New York's existing regulations prohibit an oil or gas well within 50 feet of any water body; however, a 1992 EIS for the New York oil and gas program proposed increasing that distance to 150 feet for the entire well site. The 2011 draft Supplement to that EIS proposes prohibiting high-volume hydraulic fracturing within the 100-year floodplain.

Further work is needed to establish setbacks and areas where oil and gas activities should be prohibited in order to protect public health, public safety and sensitive natural environments. Setbacks may include provisions to:

- Protect neighbors and surface owners from safety hazards, noise or other impacts
- Establish setbacks from property lines
- Protect wetlands and streams

Areas prohibited from oil and gas activity may include:

- 100-year floodplain
- Water supply watersheds
- State parks, forests, game lands and natural heritage sites

5. Develop a state stormwater regulatory program for oil and gas drilling sites.

The impacts of stormwater discharges from oil and gas exploration and production are substantially similar to the impacts from the construction and industrial activities that occur in North Carolina today. Oil and gas exploration and production can disturb large areas of land to develop impervious well pad sites, creating significant impacts related to sedimentation and erosion, water quality pollution, increased peak discharges, increased frequency and severity of flooding, and other stormwater concerns.

However, unlike existing construction and industrial activities, oil and gas exploration and production activities are exempt from the requirements of the National Pollutant Discharge Elimination System (NPDES) stormwater permit program under the federal Clean Water Act unless there has been a documented water quality standard violation, or release of a reportable quantity of oil or hazardous substance. Since North Carolina has relied on the federal stormwater permitting programs to manage industrial stormwater impacts, the state is not prepared to effectively manage stormwater impacts associated with oil and gas production.

We recommend that the General Assembly authorize a state stormwater regulatory program for oil and gas activities, including requirements for stormwater permitting, inspections and compliance activities.

6. Develop specific standards for management of oil and gas wastes.

a. *Solid Waste*. Many of the waste products of the oil and gas industry are exempt from federal hazardous waste rules, but some have the characteristics of hazardous wastes. As a result, oil and gas-producing states generally have specific standards for wastes generated by oil and gas production. Since those wastes are not specifically addressed by North Carolina's waste manage program, we recommend the development of a regulatory program to address the unique characteristics of solid wastes associated with oil and gas during transportation, on-site storage and final disposal.

Recommended requirements include:

- Industrial and MSW landfills' operational plans should be required to include radiation monitoring at the working face of the landfill when exploration and production waste is being accepted.
- Exploration and production waste should only be allowed in a landfill with a liner and leachate system design that is equivalent to the design requirements for an MSW landfill. Current standards for construction of a MSW landfill allow use of one of four liner systems. These same liner alternatives exist for industrial landfills. Prohibiting oil and gas waste from unlined landfills will require a change in existing rules.
- Industrial landfills (in the event that the shale gas industry will choose to site and can permit a landfill in North Carolina) do not at this time receive disposal fees. It is recommended that fees be assessed for this type of waste at industrial landfills.
- All exploration and production industrial wastes accepted into MSW landfills, including those allowed by permit to be used as alternative daily cover, should always be considered waste and must be assessed appropriate fees. We recommend that these types of waste not be excluded from fee assessments at an industrial landfill.
- There has not been research on the possible interaction between chemicals used in industrial processes and wastes in MSW landfills and possible impacts on the liner or leachate systems. The possibility of the chemical solutions compromising landfill integrity must be thoroughly assessed before these exploration and production wastes are allowed into existing or new MSW landfills. We recommend a comprehensive study to determine if design or operation should be changed for this particular waste stream.

b. *Solid waste and wastewater*. Prohibit land application of solid waste and wastewater from oil and gas activities because of environmental impacts and the lack of sufficient capability to dispose of all waste generated.

c. *Wastewater*. Maintain the state's prohibition on underground injection of wastewater due to North Carolina's unsuitable geology and seismic risks.

d. *Wastewater*. Encourage a wastewater management hierarchy in which the preferred order of disposal options for oil and gas wastewater is 1) recycling and reuse of hydraulic fracturing fluids, 2) a pretreatment program, and 3) centralized waste treatment facilities.

7. Require full disclosure of hydraulic fracturing chemicals and constituents to regulatory agencies. With the exception of trade secrets, require public disclosure of hydraulic fracturing chemicals and constituents.

We recommend that the General Assembly require full disclosure of hydraulic fracturing chemicals and constituents to the state regulatory agency and to local government emergency response officials. We also recommend that the General Assembly should require the industry to disclose all hydraulic fracturing chemicals and constituents – except for information protected under North Carolina law as a trade secret – to the public through the FracFocus website or a state agency website.

8. Prohibit the use of diesel fuel in hydraulic fracturing fluids

The use of diesel fuel in fracturing fluid is a concern because it contains toxic constituents, including the BTEX compounds benzene, toluene, ethylbenzene, and xylenes. Benzene is a human carcinogen, while chronic exposure to toluene, ethylbenzene, or xylenes can damage the central nervous system, liver and kidneys. We recommend that its use as a hydraulic fracturing constituent be completely prohibited.

9. Improve data management capabilities and develop an e-permitting program

A robust data management system including GIS tools is needed to:

- Collect baseline water quality and air quality data
- Track production of oil and gas activities for royalties/severance tax
- Facilitate public disclosure of hydraulic fracturing constituent information
- Provide electronic permitting to the industry to allow for efficient and effective collection and distribution of data, particularly when concerns about pollution occur
- Enable the permitting, inspection and enforcement system to be as effective as possible

DENR currently has no computer data management capabilities with respect to oil and gas regulatory activities. The STRONGER review noted this deficiency of North Carolina's programs in comparison to STRONGER's guidelines. In order to effectively manage the large volumes of reporting information associated with baseline sampling, production, drilling logs and hydraulic fracturing, and to make this information available to interested parties in the public, industry and other state agencies, North Carolina will need to make substantial investments in electronic databases and online reporting tools. A sound electronic data management system benefits the public by providing increased, and more timely, public awareness of industry activity and environmental impacts; benefits industry and landowners by making exploration data available to guide additional exploration and leasing decisions; and benefits the state by allowing for improved tracking of revenue from severance taxes.

10. Ensure that state agencies, local first responders and industry are prepared to respond to a well blowout, chemical spill or other emergency.

- We recommend that oil and gas operators be required to develop an emergency response plan; state criteria for an acceptable plan should include a requirement that a wild-well qualified person be on the well pad at all times and 911 addressing of all well locations.

  If shale gas development occurs in North Carolina, local governments will require additional funds to train their local emergency services providers. These providers will need training in responding to a variety of potential emergencies that could occur as a result of large truck accidents, hazardous materials truck accidents and accidents on drilling sites.

- We recommend that the General Assembly encourage the Department of Labor to review its readiness to inspect drilling sites and appropriately enforce the OSHA standards for this industry to prevent worker injuries or death.

11. Develop a modern oil and gas regulatory program, taking into consideration the processes involved in hydraulic fracturing and horizontal drilling technologies, and long-term prevention of physical or economic waste in developing oil and gas resources.

- We recommend that the General Assembly authorize DENR to establish a complete regulatory program for oil and gas management, including oversight, compliance, inspections, recordkeeping and notice provisions that will complement the existing regulatory framework for regulation of the oil and gas industry
- In addition, we recommend several specific items below:
  - Establish well pad density requirements, to limit surface disturbance from well pads and pipelines
  - Require the regulatory agency to be on site during gas well cementing
  - Provide non-recurring funding to DENR for the first few years of the regulatory program

- Fund a regulatory program that is sufficient to provide rigorous oversight and regular inspections
- Under the existing statute, bonds collected for oil and gas wells can only be used to plug abandon wells. We recommend broadening this authority to include using bonds for reclamation and remediation of sites contaminated by oil and gas activities.
- Develop defensible and enforceable state water quality standards for constituents used in hydraulic fracturing to address potential adverse effects to public health and the environment

12. Keep the environmental permitting program for oil and gas activities in DENR where it will benefit from the expertise of state geological staff and the ability to coordinate air, land and water quality permitting.

Currently the Secretary for the Department of Environment and Natural Resources has authority to adopt rules to administer an oil and gas program permitting program. In addition, existing environmental regulatory programs in DENR have authority (through DENR or a citizen commission) to adopt rules for the aspects of oil and gas production regulated by those programs. We recommend that existing administrative structures and authorities be used to regulate the oil and gas industry, rather than creating a new regulatory agency. The state may rely on the DENR Secretary's existing authority from the Oil and Gas Act or expand the authority of the Mining Commission or the Environmental Management Commission to regulate this industry. Consistent with the STRONGER report, keeping the environmental regulation of the oil and gas industry in DENR will allow coordination of environmental reviews and provide more efficient service delivery for the industry.

13. Develop a coordinated permitting process.

DENR has the ability to develop a permitting process that coordinates among the various agencies that will require environmental permitting for oil and gas activities.

14. Address the distribution of revenues from oil and gas excise taxes and fees to support the oil and gas regulatory program, fund environmental initiatives, and support local governments impacted by the industry.

- In other oil- and gas-producing states, revenues from oil and gas fees and taxes are used to support conservation initiatives, offset costs to local governments impacted by the industry and for reclamation and remediation of lands impacted by oil and gas drilling. We recommend that in North Carolina, revenues collected from severance taxes and program fees should fund:

- the administration of the oil and gas program;
- conservation initiatives, including land and water conservation and the improvement of water and wastewater infrastructure;
- reclamation and remediation of any lands adversely impacted by oil and gas exploration and production;
- Repair, maintenance and improvement of local government infrastructure impacted by gas development activities; and
- Support for community services impacted by the industry.

Further study is needed to determine the distribution amounts for each of these needs.

- North Carolina's current severance tax rate is lower than that of any other state that charges a severance tax. Further study is needed to determine an appropriate severance tax rate.
- In addition to a permit fee, an annual fee is needed to perform annual inspections of oil and gas sites. Permit fees are collected once and are designed to pay for the cost of reviewing applications for permission to drill. However, for an oil and gas program to effectively oversee oil and gas drilling sites, inspections must be conducted at various stages throughout the process, such as cementing and casing of the well, drilling the well and hydraulic fracturing. Inspections must also occur yearly or at some other regular interval. Ensuring that these processes are performed according to the regulatory requirements is critical to the protection of public health, groundwater resources, surface water resources, and land resources. Severance taxes can be a volatile revenue source, increasing or decreasing based on the natural gas market. However, the need to inspect oil and gas sites exists whether or not the market is booming. Because the costs for administering the program are annual and ongoing, we recommend that if North Carolina conducts more oil and gas exploration and production, an annual fee be assessed to recover the costs of inspections and data collection related to those inspections, rather than depending on severance tax revenue to pay for this set of program costs.

15. Identify a source of funding for repair of roads damaged by truck traffic and heavy equipment.

We recommend that the General Assembly direct the North Carolina Department of Transportation to study the issue of road management and options for mitigating the impacts of increased traffic on roads, such as requiring bonds or road use management agreements.

16. Clarify the extent of local government regulatory authority over oil and gas exploration and production activities.

We recommend that the General Assembly address the issue of local zoning preemption and be clear about the authority that remains at the local level with regard to oil and gas exploration and production activities. Several models exist in other oil and gas-producing states for sharing authority between state and local government.

17. Complete additional research on impacts to local governments and local infrastructure.

We recommend that the General Assembly request assistance for additional research on the impacts of this industry to local governments from the UNC School of Government, the North Carolina League of Municipalities, the North Carolina Association of County Commissioners, or other organizations with expertise on these issues.

18. Complete additional research on potential economic impacts.

Section 5 of this report provides an estimate of economic impacts on the North Carolina economy related to new gas drilling activities, specifically directional drilling of gas wells in the Sanford sub-basin of the Deep River Triassic Basin. The economic impact analysis does not take site preparation, leasing of land, hydraulic fracturing or extraction, production or transmission of gas into consideration. While a review of the natural gas industry was conducted in order to potentially model economic impacts, uncertainty about data quality did not permit further analysis. Data quality issues resulted primarily from a lack of survey-based, real-world industry cost and supply chain relationship data. This survey approach would be necessary due to the absence of well-defined data in the matrix that underlies the modeling tool. Follow-on analysis with better data is recommended.

19. Address the natural gas industry's liability for environmental contamination caused by exploration and development, particularly for groundwater contamination.

Accidents and equipment failure can cause spills, leaks and other environmental contamination even with the best regulations in place. At the federal level, the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) establishes cleanup standards and liability for hazardous waste contamination. However, CERCLA expressly excludes petroleum and natural gas. As a result, state regulators face the task of assigning financial and cleanup responsibility. We recommend that the General Assembly further study this issue.

20. Provide additional public participation opportunities

Use technical advisory groups to develop specific requirements for an oil and gas program.

B. Limitations

As requested by the General Assembly, this report analyzes the potential environmental, health, economic, social and consumer protection impacts that an oil and gas extraction industry may have in North Carolina. The analysis is constrained by the limited information available at this time. We do not have detailed or comprehensive information on the extent and richness of the shale gas resource in North Carolina. For purposes of this report we have been forced to extrapolate from data gathered from only two wells in the Sanford sub-basin; those well values have been averaged to project an estimate of the natural gas resource potentially available in that sub-basin. Since there are only two data points and the two wells have significantly different values, it is not clear how well the average value represents the resource throughout the Sanford sub-basin. This report generally uses the Sanford sub-basin as the basic unit for analysis of all impacts because the available data came from that sub-basin. The Sanford sub-basin represents only a fraction of the total Triassic Basin formations in the state – approximately 59,000 acres out of a total of 785,000 acres that are estimated to be able to produce hydrocarbons.

These limitations carry over into the assessment of both potential economic and environmental impacts. DENR projected the number of wells and total gas production *for the Sanford sub-basin,* using the limited data derived from averaging the values of two wells. Those projections are used throughout the report as the basis for assessing economic and environmental impacts.

Many impacts of natural gas extraction will vary based on local characteristics, such as water resources and even the weather. For example, the depth and quality of groundwater resources in the Triassic Basins of North Carolina appear to be very different from conditions in the Marcellus shale formations in Pennsylvania. North Carolina does not seem to have as great a separation between potential drinking water resources and the gas-producing zone; understanding the geology and groundwater hydrology of North Carolina's shale formations will be critical to ensuring protection of drinkable groundwater. In terms of infrastructure impacts, weather can be an important factor. A local government official in Pennsylvania told DENR staff that when the natural gas industry first came to Pennsylvania from the South, oil and gas operators were surprised at how the harshness of the winters magnified the road damage caused by heavy oil and gas trucks.

There are some aspects of oil and natural gas extraction for which data is extremely limited even at a national level; the limited time available to prepare this report prevented us from taking into account additional research that is currently underway. This includes EPA's research on potential groundwater impacts in Pavillion, Wyo., and Dimock, Pa. and EPA's study of hydraulic fracturing and its potential impact on drinking water resources. EPA's first report of results related to drinking water is expected in 2012; the final report is not expected until 2014. To our knowledge, no comprehensive studies are currently available on the long-term impacts to health from hydraulic fracturing for natural gas, and DENR is not qualified to conduct such a study. DENR recognizes that questions remain about health impacts. The EPA drinking water study may provide additional insight on health effects. In March 2012, the New York State Assembly proposed $100,000 in its budget for an independent health impact study of hydraulic fracturing to be conducted by a school of public health following a model recommended by the Centers for Disease Control and Prevention.[551]

[551] NECN.com. "NY Assembly calls for fracking health impact study." March 12, 2012. Retrieved March 13, 2012 from http://www.necn.com/03/12/12/NY-Assembly-calls-for-fracking-health-im/landing_health.html?&apID=a9b8ae79569f4888b6a7e1fc0d7821bd.

Section 10 – Appendices

A. Appendix A: Bridges in the Triassic Basins with minimum clearance

Table 10-1. Bridges in the Triassic Basins with Minimum Clearance

DIV	COUNTY	ROUTE	ACROSS	LOCATION	Minimum Vertical Clearance
10	ANSON	NC109	W.S.S.B. RR.	0.5 MI. N. JCT. SR1716	24.8
8	CHATHAM	SR1012	US1	0.4 MI. N. JCT. SR1011	16.6
8	CHATHAM	SR1927	SCL RR	0.1 MI.S. JCT. SR1101	22.4
8	CHATHAM	NC42	NORFOLK SOUTHERN RR	0.11 MI. N. JCT. SR1921	22.8
8	CHATHAM	SR1931	US1	0.3 MI. N. JCT. SR1011	16.9
8	CHATHAM	SR1972	US1	1.3 MI. N. JCT. SR1011	16.5
8	CHATHAM	SR1910	US1	0.4 MI.N.JCT.SR1011	16.4
8	CHATHAM	US1 SBL	SR1011 & SEABOARD RR	0.5 MI. N. JCT. SR1910	21.0
8	CHATHAM	US1 NBL	SR1011 & SEABOARD RR	0.5 MI. N. JCT. SR1910	21.9
5	DURHAM	US501NBL	I85&US 501	@ JCT.US501&U-85	17.2
5	DURHAM	NC55	NC147	0.76 MI.N.JCT.SR1945	16.3
5	DURHAM	US70WBL	I85/US15(NBL'S)	0.35 MI W SR1670	17.6
5	DURHAM	US70BUS.	US15BYP/US501BYP	0.27 MI.E.JCT.SR1401&US70	16.5
5	DURHAM	SR1127	US15BUS/US501BUS	0.02 MI S JCT SR1308	15.8
5	DURHAM	PETTIGREW ST	NC55	0.1 MI.N.JCT.NC55&NC147	13.8
5	DURHAM	US15/US501	US15/US501BUS	0.43 MI.N.JCT.SR1209	16.5
5	DURHAM	US70 EBL	SR1670(GEER STREET)	0.36 MI.E.JCT.SR1800	16.2
5	DURHAM	US70	SR1670(GEER STREET)	0.36 MI.E.JCT.SR1800	15.5
5	DURHAM	SR1303	US15BYP/US501BYP	50'W.JCT.SR1358	16.3
5	DURHAM	US15/501 S	NC147	US15/501(BUS)	16.2
5	DURHAM	US15/US501 NBL	SR1308	0.2MI.N.JCT.SR1303	14.8
5	DURHAM	US15/US501	SR1308	0.2MI.N.JCT.SR1303	15.1
5	DURHAM	NC751	US15BUS/US501BUS	0.24 MI S JCT S1303	14.3
5	DURHAM	SR2028	I40	0.25 MI.N.JCT.NC54	17.3
5	DURHAM	SR1800	US70 BYP	0.6 MI E JCT SR1670	16.7
5	DURHAM	US70 EBL	NC98	1.0 MI.E.JCT.SR1800	16.3
5	DURHAM	I85 NB	SR1401	1.0MI.S.JCT.SR1321	15.8
5	DURHAM	US15BYP/US501NBL	NC751	1.0 MI S JCT SR 1317	16.1
5	DURHAM	I85 S.B.	SR1401	1.0 MI S JCT SR 1321.	16.1
5	DURHAM	US15BYP/US	NC751	1.0 MI S JCT SR 1317	15.5
5	DURHAM	US15/501SB	NORFOLK SOUTHERN RAILWAY	0.5MI S.JCT I85	22.0
5	DURHAM	US70 WBL	NC98	1.0 MI E JCT SR 1800	14.3
5	DURHAM	US70BUS WB	US70 EBL	0.2MI.W.JCTSR1922	14.5
5	DURHAM	SR1317	US15BYP/US501BYP	1.6 MI S JCT US 701BUS	16.4
5	DURHAM	SR1321	I85	@JCT.I-85&SR1321	18.0
5	DURHAM	I85	NC157	0.6MI.N.JCT.I-85&SR1321	15.8
5	DURHAM	US15/501SB	I85NB&US70EB	0.2 MI N JCT SR1401	17.7
5	DURHAM	BROAD ST.	I85	0.7 MI.S.JCT.I85&US501	16.9
5	DURHAM	SR1322	NC147	0.15 MI.S.JCT.US70 BUS.	17.1
5	DURHAM	NC147 SBL	CAMPUS DRIVE	0.4 MI.S.JCT.SR1320	21.2
5	DURHAM	NC147 NBL	CAMPUS DRIVE	0.4 MI.S.JCT.SR1320	20.0
5	DURHAM	NC147 SBL	BUCHANAN BLVD	0.7 MI.E.JCT.SR1320	16.5
5	DURHAM	SR1127	NC147	0.1 MI.W.SR1361	16.3
5	DURHAM	WASHINGTON	I85&US70	0.3MI.N.JCT.I85&US501BYP	17.7
5	DURHAM	I85SB&US70	CLUB BOULEVARD	0.45MI.N.JCT.US501BYP	15.3
5	DURHAM	SR1361	NC147	0.2 MI.S.JCT.US70 BUS.	19.0
5	DURHAM	SR1445	NC147	0.3 MI.S.JCT.SR1127	15.9
5	DURHAM	NC147SBL	SR1359(BLACKWELL ST)	0.2 MI.N.JCT.US501	18.5
5	DURHAM	I85N/US15N	US15/501 BUS	0.19 M S JCT. NC55	18.8
5	DURHAM	I85S/US15/	US 501 BUS	0.19MI S JCT NC55	17.2
5	DURHAM	NC147 NBL	SR1359 (BLACKWELL ST)	0.2 MI.N.JCT.NC147	15.7
5	DURHAM	NC147 SBL	US15/501 NBL(BUS)	0.1 MI.S.JCT.US15/501 SBL	18.8
5	DURHAM	NC147 NBL	US15/501 NBL(BUS)	0.1 MI.S.JCT.US15/501 SBL	15.3
5	DURHAM	I85 NBL	NC55	JCT. I-85&NC55	18.7

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Table 10-1, continued

DIV	COUNTY	ROUTE	ACROSS	LOCATION	Minimum Vertical Clearance
5	DURHAM	I85 SB&US1	NC55	JCT.OF I-85&NC55	19.6
5	DURHAM	SR1118	NC147	100' S.SR1364	15.7
5	DURHAM	NC147 SBL	GRANT ST.	0.3 MI.N.NC147 & NC55	20.8
5	DURHAM	NC147 NBL	GRANT ST.	0.3 MI.N.JCT.NC147 & NC55	15.3
5	DURHAM	NC147 SBL	BACON STREET	0.4 MI.S.JCT.NC55	15.8
5	DURHAM	I85 SB/US15SBL	SR1671	0.5 MI N.JCT NC55	16.3
5	DURHAM	NC147 NBL	BACON STREET	0.4 MI.S.JCT.NC55	16.4
5	DURHAM	I85	NORFOLK &WESTERNRR	0.7 MI N JCT NC55	22.9
5	DURHAM	BRIGGS AVE	NC147	@ JCT.BRIGGS AVE&NC147	16.9
5	DURHAM	SR1827	I85	0.18 MI.N. SR1670	16.9
5	DURHAM	NC147 SBL	SR1171	1.5 MI.S.JCT.NC55	16.1
5	DURHAM	NC147 NBL	SR1171	0.2 MI.E.JCT.SR2161	17.9
5	DURHAM	SR1671	I85/US15	.25 MI E JCT SR 1636	16.8
5	DURHAM	SR1940	NC147	0.2 MI.N.JCT.SR2020	16.8
5	DURHAM	SR1675	I85	0.70 MI. N. OF SR1671	16.2
5	DURHAM	NC147 NBL	SR1954	1.05 MI.N.JCT.SR2028	16.6
5	DURHAM	NC147 NBL	SR1954	1.05 MI.N.JCT.SR2028	19.6
5	DURHAM	I85 NBL&US	SR1632	0.33 MI.S.JCT.SR1637	13.8
5	DURHAM	I85 SBL&US15	SR1632	.33 MI.S.JCT.SR1637	14.6
5	DURHAM	SR2028	NC147	0.75 MI.S.JCT.SR1959	16.3
5	DURHAM	SR1121	NC147	0.3 MI.N.SR2017	16.8
5	DURHAM	NC147 RAMP	NC147 NBL	0.5 MI.S.JCT.SR1121	16.5
5	DURHAM	I85&US15 N	SR1637 & SOUTHERN RR	.33 MI.N.JCT.SR1632	19.2
5	DURHAM	I85 & US15	SR1637 & SOUTHERN RR	0.5 N.JCT.SR1632	19.2
5	DURHAM	I85&US15 N	SR1637	1.43 MI.N.JCT SR1632	14.2
5	DURHAM	I85& US15	SR1637	1.4 MI.N JCT SR1632	14.8
5	DURHAM	SR1999	I40	0.3 MI N JCT NC 54	16.2
5	DURHAM	SR1959	I40	.3MI.S.JCT.SR2058	16.0
5	DURHAM	I40 WBL	NC55	1.1 MI.W.JCT.I40 & NC147	21.2
5	DURHAM	I40 EBL	NC55	1.1 MI.W.JCT.I40 & NC147	18.4
5	DURHAM	I40 WBL	SR1945	0.3 MI.E.JCT.NC55	18.0
5	DURHAM	I40 EBL	SR1945	0.3 MI.E.JCT.NC55	15.3
5	DURHAM	I40 WBL	NC147	0.3 MI.E.JCT.SR2028&I-40	16.4
5	DURHAM	I40 EBL	NC147	0.3 MI.E.JCT.SR2028&I-40	16.4
5	DURHAM	I40	NC147 RAMP	0.5 MI.E.JCT.SR2028	0.0
5	DURHAM	NC54	9906 (Triangle Pkwy)	0.14 MI.E.JCT.SR2028	21.9
5	DURHAM	US15/501	I40	@ JCT.US15/501 & I40	16.5
5	DURHAM	SR2220	I40	0.01 MI.W.JCT.SR1113	16.5
5	DURHAM	NC751	I40	1.1 MI.S.JCT.NC54	16.0
5	DURHAM	SR1118	I40	1.0 MI.E.JCT.NC751	17.6
5	DURHAM	I40 WBL	NC54	0.2 MI.E.JCT.SR1118	16.8
5	DURHAM	I40 EBL	NC54	0.2 MI.E.JCT.SR1118	16.6
5	DURHAM	SR1106	I40	0.3 MI.N.JCT.NC54	16.3
5	DURHAM	LASALLE ST	NC147	0.2 MI.S.JCT.US70 BUS.	16.8
5	DURHAM	ANDERSON S	NC147	0.2 MI.S.JCT.US70 BUS.	16.7
5	DURHAM	SR1110	I40	0.3 MI.N.JCT.SR1113	16.4
5	DURHAM	NC54	I40	0.1 MI.W.JCT.SR1110	16.5
5	DURHAM	US70 BUS	CAMPUS DRIVE	0.2 MI.E.JCT.SR1322	11.2
5	DURHAM	NC147SBL	HILLANDALE ROAD(SR1321)	JCT.OF NC147 & SR1321	15.2
5	DURHAM	NC147NBL	HILLANDALE ROAD(SR1321)	@ JCT.NC147 & SR1321	19.4
5	DURHAM	NC147 RAMP	NC147	0.5 MI.W.LASALLE STREET	17.5
5	DURHAM	US70 BUS.	SR1321	0.79 MI.E.JCT.US15-501BYP	15.3
5	DURHAM	NC147NB	SR1320	0.3MI.W.JCT.SR1322	18.4
5	DURHAM	NC147 SBL	US15/501	0.4MI.S.JCT.US70 BUS.	21.3

Table 10-1, continued

DIV	COUNTY	ROUTE	ACROSS	LOCATION	Minimum Vertical Clearance
5	DURHAM	NC147	SR1320	0.3MI.W.JCT.SR1322	14.8
5	DURHAM	NC147 NBL	US15/501 BYP.	JCT.NC147&US15/501 BYPASS	17.0
5	DURHAM	I40	SR1973	0.8 MI.W.JCT.SR1959	15.9
5	DURHAM	I540	I40	.96 MI.E.SR1973	16.7
5	DURHAM	I540	I40 & NW EXPRESSWAY	.96 MI.E.SR1973	17.6
5	DURHAM	US70 EB RAMP	I85,US70	JCT.I-85,US70	17.8
5	DURHAM	US501(GREGSON ST)	I85	@JCT I85	17.7
5	DURHAM	15/501 RAM	US15/501	@ JCT. S.PRKWY&US15/501	16.5
5	DURHAM	US15/501 R	15/501	@ JCT.S. PRK.WAY&US15/501	17.7
5	DURHAM	SR2104	I-540	JCT.SR-2104 & I-540	17.7
5	DURHAM	I-540 SB;	I-40	JCT. I-540 & I-40	17.2
5	DURHAM	I-540 NBL	I-40	JCT.I-540 & I-40	18.1
5	DURHAM	NC 147 SBL	SR1317	.65MI.N. JCT. US15/501	20.3
5	DURHAM	NC 147 NBL	SR1317	.65 MI.N.JCT US15/501	15.7
5	DURHAM	SR1978	NC147 EXT(TRIANGLE PKWY)	@ JCT NC147 EXTENTION	20.3
5	GRANVILLE	US15	I85	0.4 MI.W SR1102	16.3
5	GRANVILLE	SR1103	I85	0.3 MI.W SR1102	16.5
5	GRANVILLE	NC56	I85	0.1 MI.E.SR1215	16.3
5	GRANVILLE	SR1127	I85	0.2 MI.W SR1129	16.7
8	LEE	US1 NBL	US1 BUS,NC42	1.4 MI. S. JCT. SR1100	16.3
8	LEE	SR1483	SEABOARD COASTLINE	100 FT. W. JCT. SR1424	22.9
8	LEE	US1 SBL	US1 BUS,NC42	1.4 MI. S. JCT. SR1100	14.3
8	LEE	US1	SR1009	0.85 MI. N. JCT. NC42	16.1
8	LEE	SR1100	US1, US15/501	0.4 MI. E. JCT. SR1328	15.8
8	LEE	US1	US421	1.94 MI. N. JCT. NC42	15.3
8	LEE	SR1406	US1,US15,US501	0.2 MI. E. JCT. SR1438	18.0
8	LEE	US1	US1BUS, US15/501, NC87	2.2 MI. N. JCT. US421	15.5
8	LEE	US1 SBL	SR1415	2.7 MI. N. JCT. NC87	15.4
8	LEE	SR1426	US1	0.7 MI.W.JCT.SR1423	16.0
8	LEE	SR1423	US1	1.0 MI. N. JCT. SR1426	16.5
8	LEE	SR1466	US1	0.7 MI. E. JCT. SR1434	16.4
8	LEE	SR1400	NORFOLK SOUTHERN RR	0.7 MI. N. JCT. SR1403	22.8
8	LEE	SR1400	SOUTHERN RR	0.6 MI.N.JCT.SR1403	19.5
8	LEE	US1 NBL	SR1415	2.7 MI. N. JCT. NC87	16.3
8	LEE	US421 NBL (FUT)	US1	0.45MI.W.JCT.US1 BUS.	22.5
8	LEE	US421 (FUTURE) SBL	US1	0.45 MI. W. JCT. US1BUS	19.9
8	LEE	US421(FUT) NBL COL	US1	0.45 MI. W. JCT. US1BUS	23.1
8	LEE	US421(FUT) SBL COL	US1	0.45 MI. W. JCT. US1 BUS	17.5
8	LEE	US1 BUS.	US421,NC87 (FUTURE)	0.45 MI. N. JCT. SR1406	18.9
8	LEE	US421,NC87SBL FUT.	CSXRR,LITTLE BUFFALO CK.	0.4 MI. E. JCT. US1 BUS	23.2
8	LEE	US421,NC87NBL(FUT)	CSXRR,LITTLE BUFFALO CRK	0.4 MI. E. JCT. US1 BUS.	23.7
8	LEE	SR1415	US421,NC87 (FUTURE)	0.6 MI.E.JCT. US1BUS.	16.6
8	LEE	SR1002	US421,NC87 (FUTURE)	1.2 MI. N. JCT. SR1521	17.1
8	LEE	SR1509	US421,NC87 (FUTURE)	0.65 MI. N. JCT. SR1521	16.3

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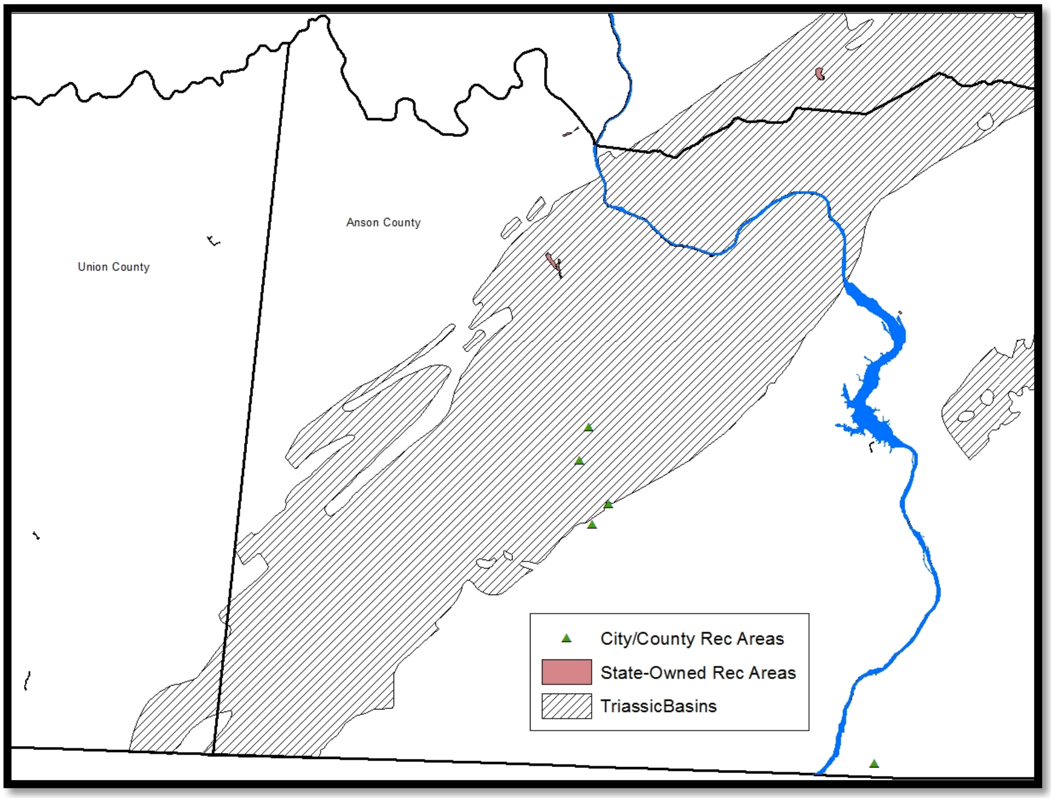
Table 10-1, continued

DIV	COUNTY	ROUTE	ACROSS	LOCATION	Minimum Vertical Clearance
8	LEE	SR1521	US421,NC87 (FUTURE)	0.65 MI. S. JCT. SR1506	16.9
7	ORANGE	SR1010 NBL	US15/US501 SBL	0.95 MI. N. JCT. SR1750	13.5
7	ORANGE	US15,US501	NC54	0.6 MI. N. JCT. SR1900	14.8
7	ORANGE	SR1734	I40	0.7 MI. N. JCT. SR1733	17.0
7	ORANGE	US15, US501 NBL	NC54	1.2 MI. S. JCT. SR1750	16.5
7	ROCKINGHAM	US220 BUS.	DAN R.,N&WRR &S.WATER ST	0.2 MI. E. JCT. US311	24.1
7	ROCKINGHAM	NC135	US220	0.20 MI. E. JCT. SR2177	14.3
7	ROCKINGHAM	NC700	NC14, NC87 & NC770	0.41 MI. W. JCT. SR1962	14.3
7	ROCKINGHAM	SR2150	US220	0.50 MI. W. JCT. NC 135	0.0
7	ROCKINGHAM	US220 NBL	NORFOLK WESTERN RR	0.57 MI. N. JCT. SR2209	22.6
7	ROCKINGHAM	US220 NBL	US220 BUS	0.6 MI. N. JCT.SR2209	14.4
7	ROCKINGHAM	NC14,NC87	C & NW RR	0.3 MI. N. JCT. NC770	22.9
7	ROCKINGHAM	US220 SBL	NORFOLK WESTERN RR	0.57 MI. N. JCT. SR2209	22.9
7	ROCKINGHAM	US220 SBL	US220 BUS	0.6 MI. N. JCT. SR2209	15.5
5	WAKE	NC55	US64	@ JCT.NC55&US64	16.8
5	WAKE	US64 EBL	SR1613	1.4MI.E.JCT NC55	15.8
5	WAKE	SR3015	I40	0.15 MI.SW SR1789	17.2
5	WAKE	NC55	US1	0.13MI.E.JCT.NC55&SR1158	16.1
5	WAKE	SR1002	I40	1.1 MI.SE SR1002	16.3
5	WAKE	SR1134	US1	0.3 MI.N.JCT.SR1189	17.3
5	WAKE	SR1127	US1	0.1 MI. N. JCT SR 1149	16.8
5	WAKE	SR1149	US1	JCT.US1&SR1149	16.9
5	WAKE	SR1153	US1	1.6 MI.S.JCT.SR1011	17.4
5	WAKE	US70	SR1002(WESTGATE RD)	1.8MI.N.W.JCT.SR1837	16.6
5	WAKE	SR1645	I540(N.WAKE EXPRESSWAY	0.68 MI.E.JCT.SR1646	17.1
5	WAKE	US64 WBL	SR1613	0.05MI.N.JCT.SR1613	17.0
5	WAKE	I540 WBL	US70	0.1 MI.S.JCT.SR1002	17.7
5	WAKE	I540 SBL R	I540&US70	0.1 MI.S.JCT.SR1002	16.8
5	WAKE	I540 EBL	US70	0.1MI.S.JCT.SR1002	17.9
5	WAKE	I540 NBL R	I540 & US70	0.1MI.S.JCT.SR1002	16.8
5	WAKE	SR1643	I540	1.3 MI.N.JCT.SR1792	17.3
5	WAKE	SR3097 RAMP E	I540 & RAMP B	0.3 OF I540 SBL	17.9
5	WAKE	SR3097 NB AV.PKWY	I540	0.7 MI.S.SR1644	17.2
5	WAKE	SR3097 SB AV.PKWY	I540	0.7 MI.S.SR1644	17.1
5	WAKE	SR3097 RAMP E	SR3097 RAMP B	0.2 MI.OF I540 SBL	17.4
5	WAKE	SR1644	I540	0.8 MI.S.JCT.AVIA.9908	17.3
5	WAKE	NC55 BYP	ACCESS RD.	1.0 MI. S. OF JCT. SR1172	15.7
5	WAKE	NC55 BYP.	ACCESS RD.	1.0 MI. S. JCT. SR1172	15.7
5	WAKE	SR1642	SR3097	0.3 E.JCT. SR 1789	16.5
5	WAKE	NC540 WBL	NC55	@ JCT.NC55	19.4
5	WAKE	NC540 EBL	NC55	@ JCT.NC55	17.2
5	WAKE	NC540 WBL	NC54,SOUTHERN R/R	@JCT.NC54	18.0
5	WAKE	NC540 EBL	NC54,SOUTHERN R/R	@JCT.NC54	20.2
5	WAKE	9906 FLYOVER	NC540 NB RMP.	@JCT.NC540	17.2
5	WAKE	NC540 FLYOVER EB	9906 TRIANGLE PKWY	@JCT.9906	17.2
5	WAKE	9906 FLYOVER	9906 TRIANGLE PKWY	@JCT.9906	33.3
5	WAKE	NC540 NB FLYOVER	NC540	@JCT.NC540	20.2
5	WAKE	I540 WBL	SR1613(DAVIS DRIVE)	@JCT.SR1613	16.7
5	WAKE	I540 EBL	SR1613(DAVIS DRIVE)	@JCT.SR1613	15.3
5	WAKE	I540 RAMP	SR1613(DAVIS DR.)	@JCT.SR1613	15.9
5	WAKE	NC540 WBL	LOUISE STEVENS RD(SR991)	0.4 MI.E.JCT.NC55	19.5
5	WAKE	NC540 EBL	LOUISE STEVENS RD(SR9910	0.4 MI.E.JCT. NC55	17.1
5	WAKE	NC540 WBL	ACCESS RD.	0.7 MI.E.JCT.NC55	16.7
5	WAKE	NC540 EBL	ACCESS RD.	0.8 MI.E.JCT NC55	17.3
5	WAKE	SR3112(CARY PKWY)N	SOUTHERN RAILROAD	0.3 MI.S.JCT.NC54	23.7
5	WAKE	SR3112(CARY PKWY)S	SOUTHERN RAILROAD	0.3 MI.S.JCT.NC54	23.3
5	WAKE	SR1615	NC540	@ JCT.NC540	18.0
5	WAKE	SR1621	NC540	0.5 MI.E.JCT.SR1600	17.3
5	WAKE	SR1624	NC540	0.6 MI.E.JCT.SR1625	17.6
5	WAKE	MCCRIMMON PKWY	NC540	0.9 MI.W.JCT.NC55	17.8
5	WAKE	MCCRIMMON PKW	NC540	0.9 MI.W.JCT.NC55	17.8
5	WAKE	SR1002 RAMP	SR3015	@ JCT.SR3015	17.4
5	WAKE	SR1002 SBL	SR3015	@ JCT.SR3015	17.2
5	WAKE	SR1002 NBL	SR 3015	@ JCT.SR3015	16.7
5	WAKE	SR1002 RAMP	SR1002 NBL	@ JCT.SR1002	17.4
5	WAKE	SR1002 SBL	SR3015 WBL	@ JCT.SR3015	16.7
5	WAKE	SR1002 SBL RAMP	SR3015	@ JCT.SR3015	27.2
5	WAKE	SR1002 NBL	SR3015 WBL		16.8

B. Appendix B: Maps of recreation areas

Maps of state, county, and local parks

Figure 10-1. Anson County State, County and Local Parks



Not all city and county parks are included in this map. Anson County does not keep mappable data for these sites.

Figure 10-2. Chatham County State, County and Local Parks

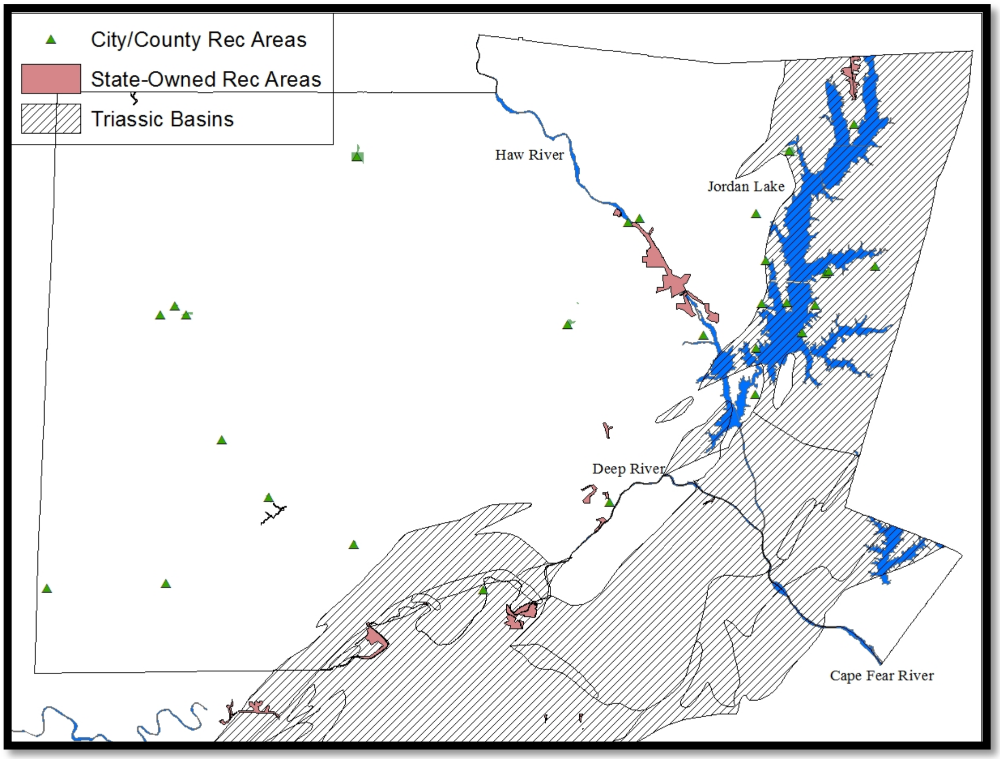
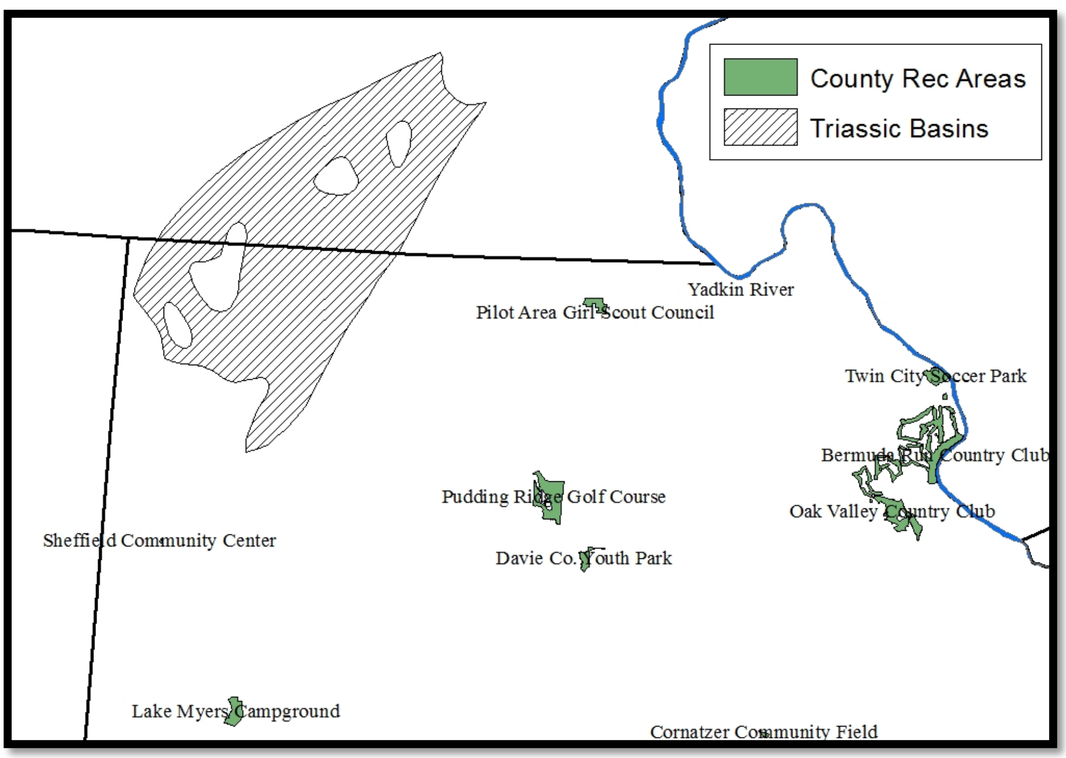


Figure 10-3. Davie County State, County and Local Parks



Not all city parks are included in this map. Davie County does not keep mappable data for these sites.

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Figure 10-4. Durham County State, County and City Parks

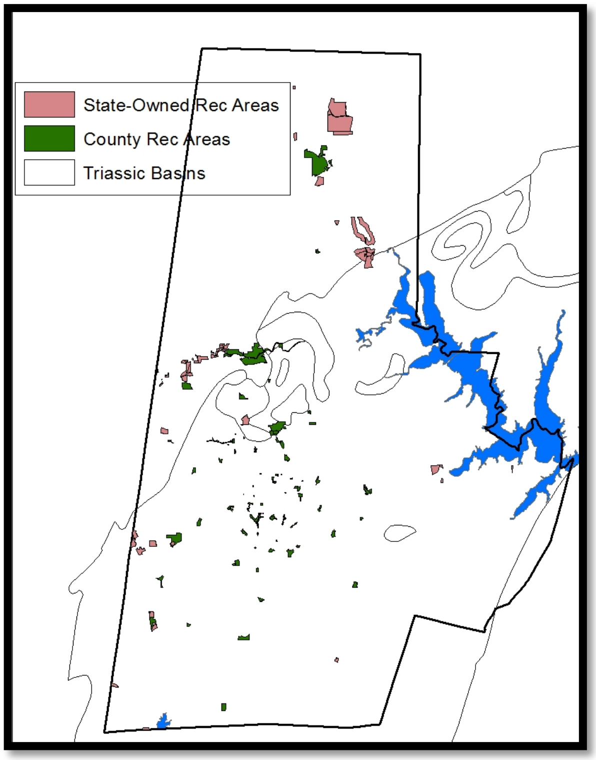
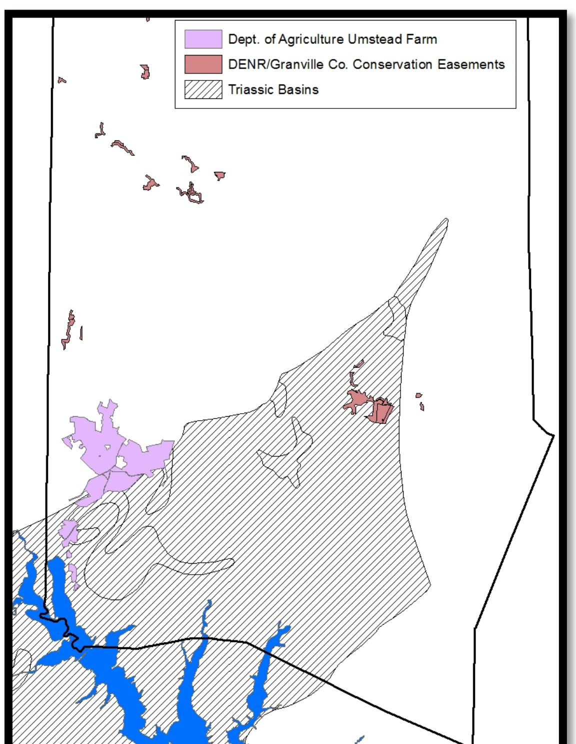
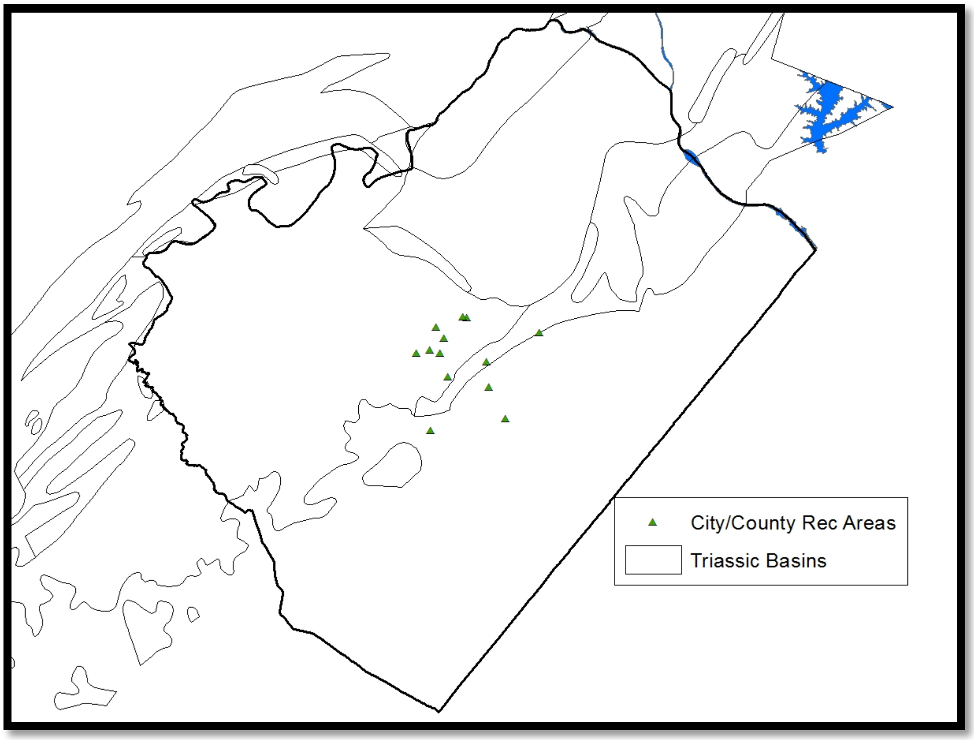


Figure 10-5. Granville County State, County and Local Parks



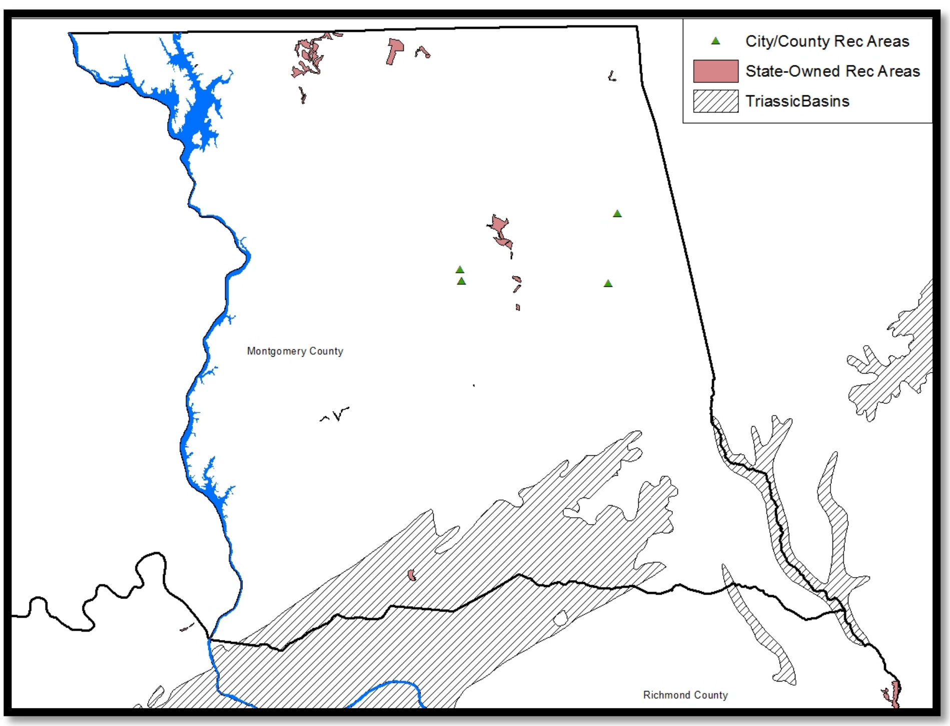
Not all city/county parks are included in this map. Granville County does not keep mappable data for these sites.

Figure 10-6. Lee County State, County and Local Parks



Not all city/county parks are included in this map. Lee County does not keep mappable data for these sites.

Figure 10-7. Montgomery County State, County and City Parks



Not all city/county parks are included in this map. Montgomery County does not keep mappable data for these sites.

Figure 10-8. Moore County State, County and City Parks

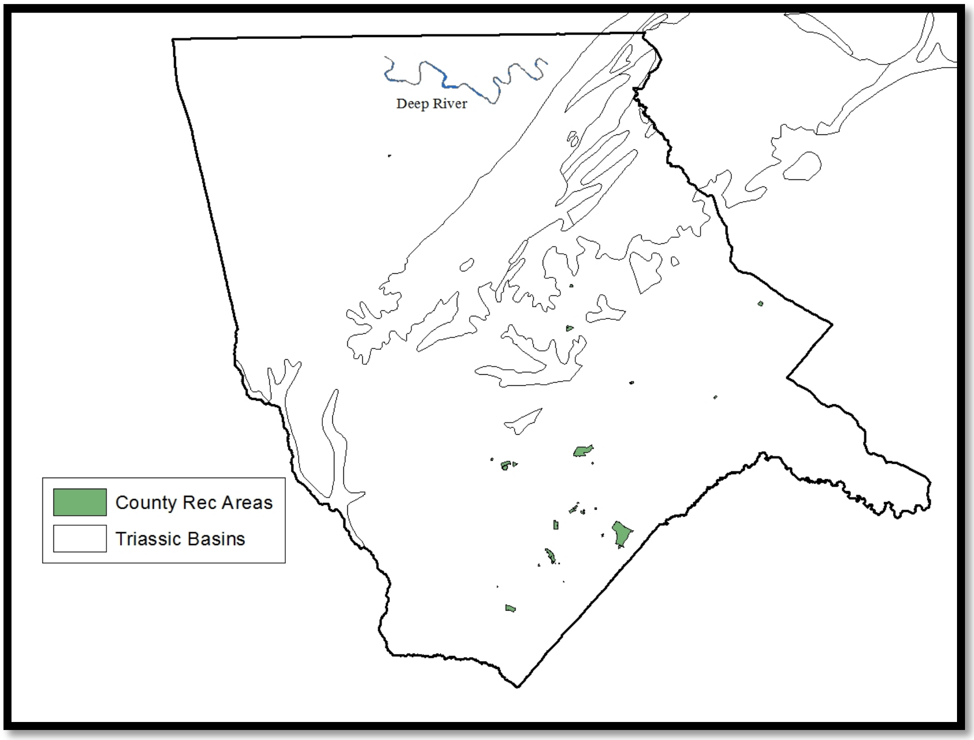


Figure 10-9. Orange County State, County and City Parks

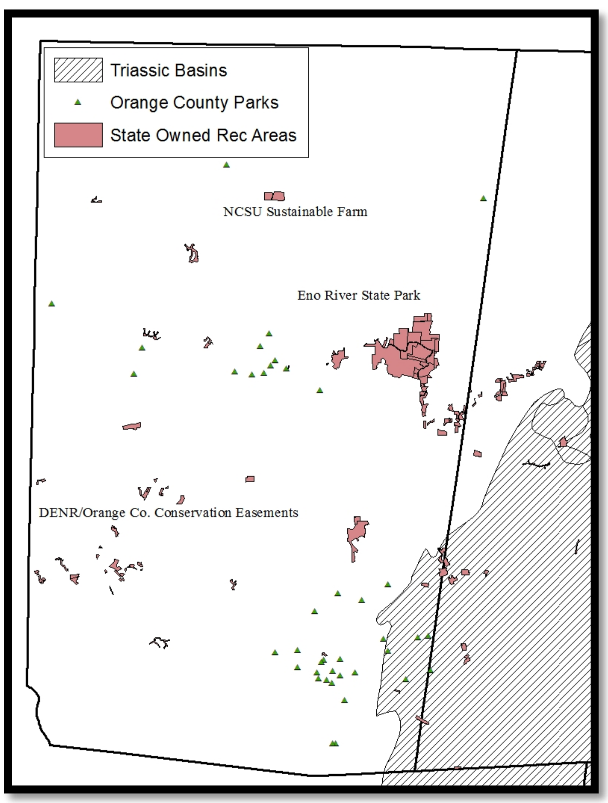


Figure 10-10. Richmond County State, County and City Parks

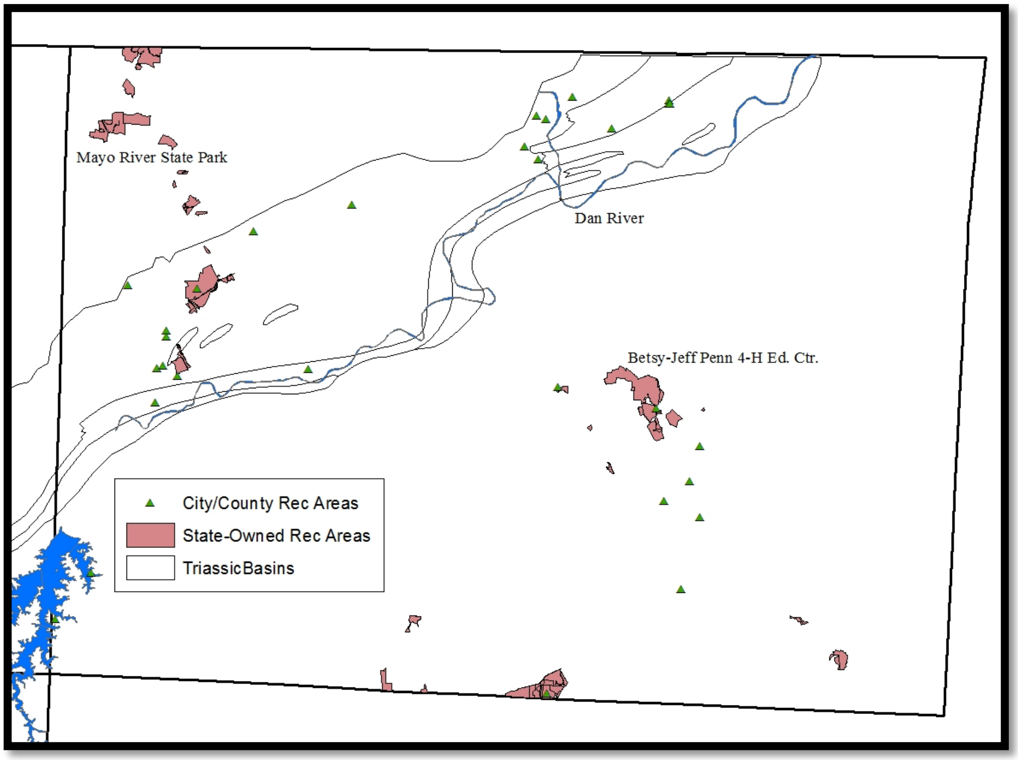


Figure 10-11. Rockingham County State, County and City Parks

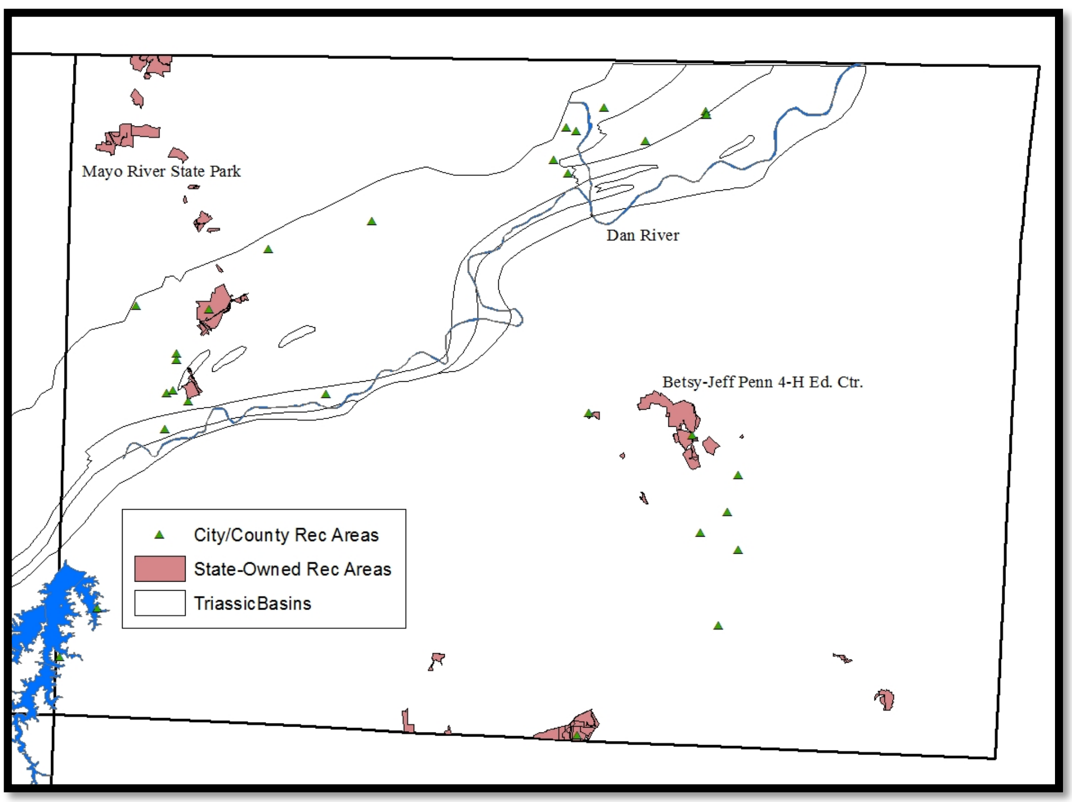


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Figure 10-12. Stokes County State, County and City Parks

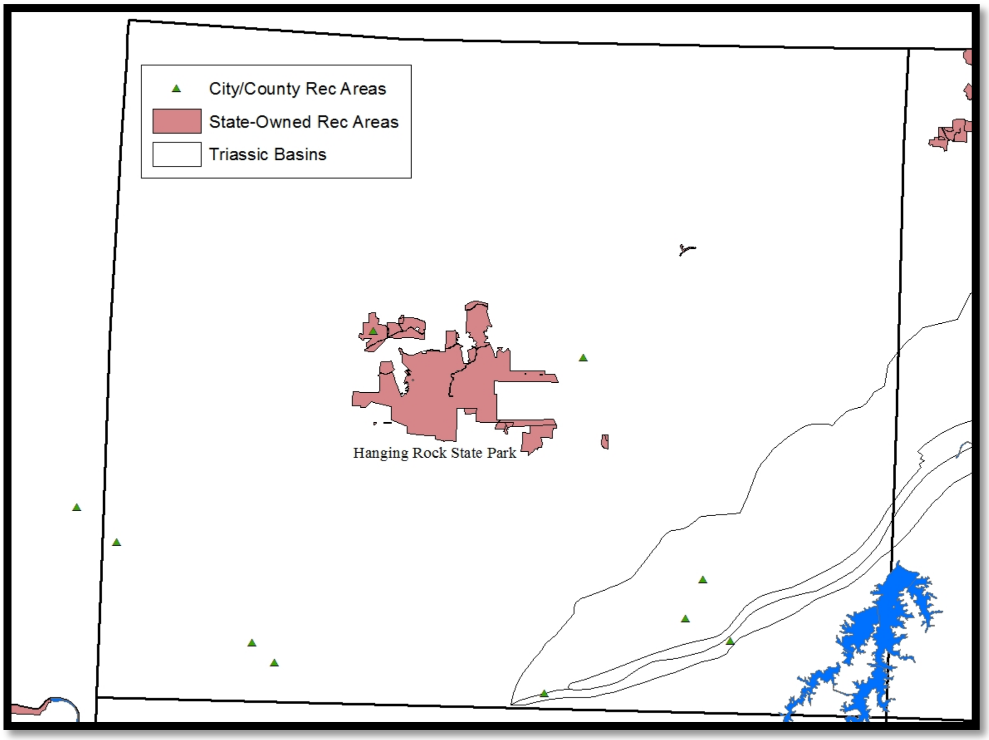
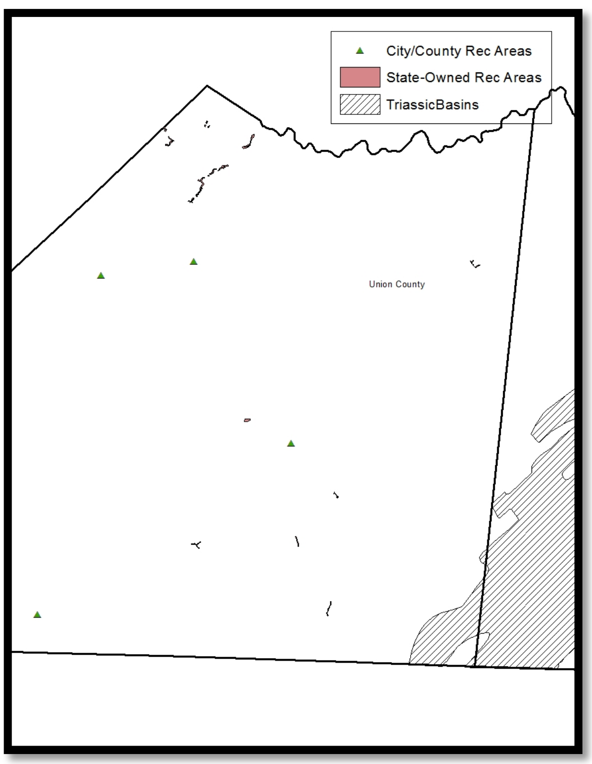


Figure 10-13. Union County State, County and City Parks



Not all city/county parks are included in this map. Union County does not keep mappable data for these sites.

Figure 10-14. Wake County State, County and City Parks

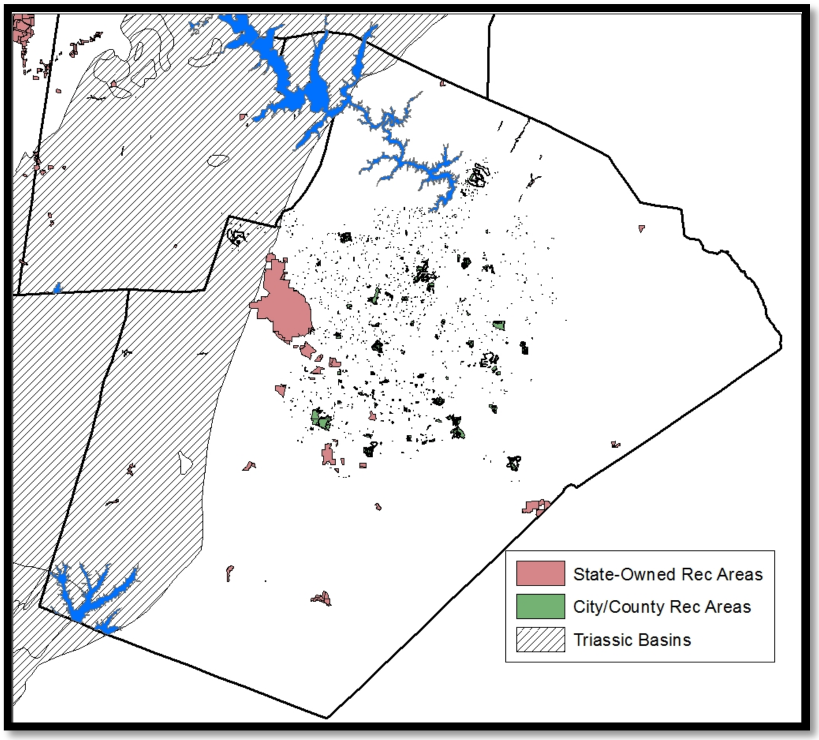
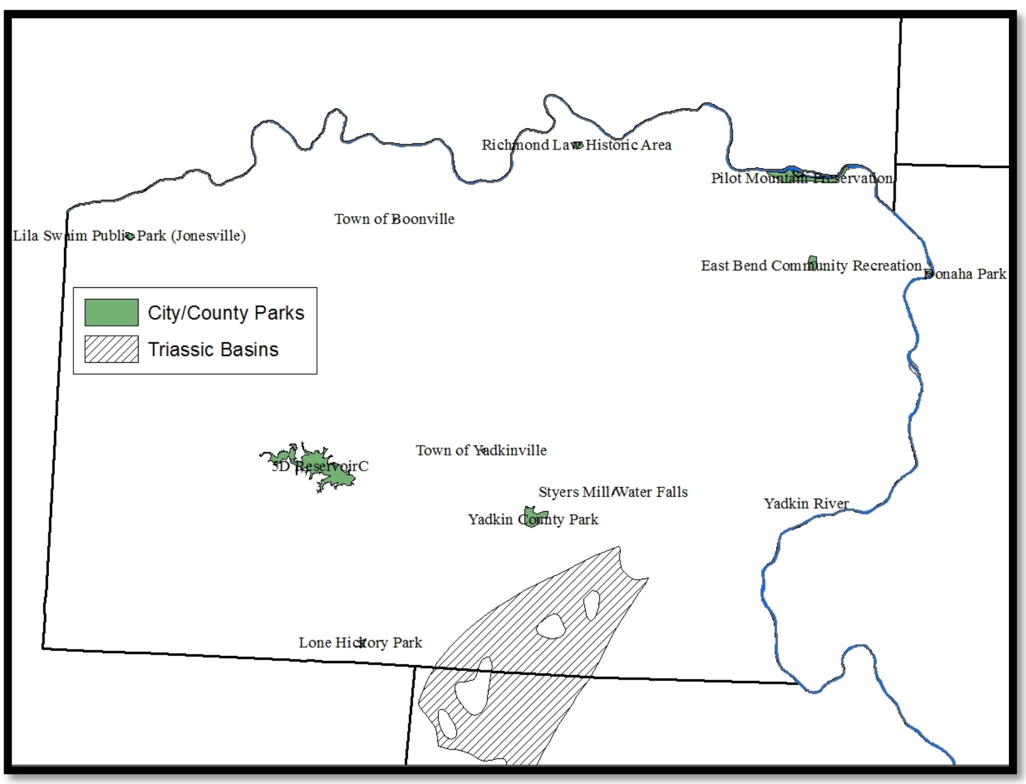


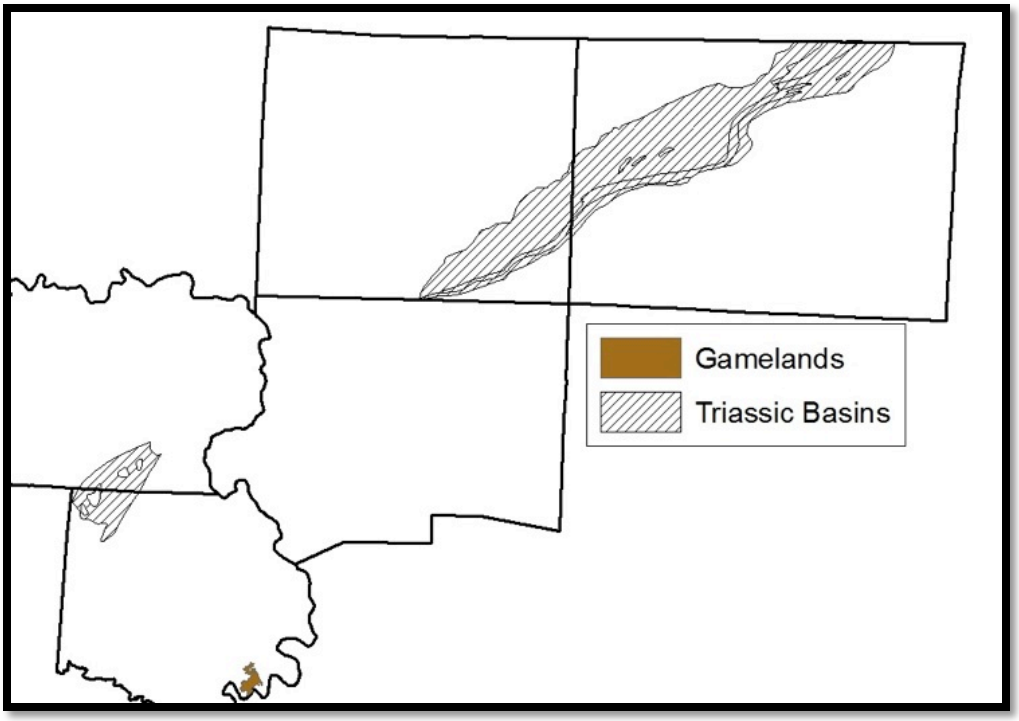
Figure 10-15. Yadkin County State, County and City Parks



Not all city/county parks are included in this map. Yadkin County does not keep mappable data for these sites.

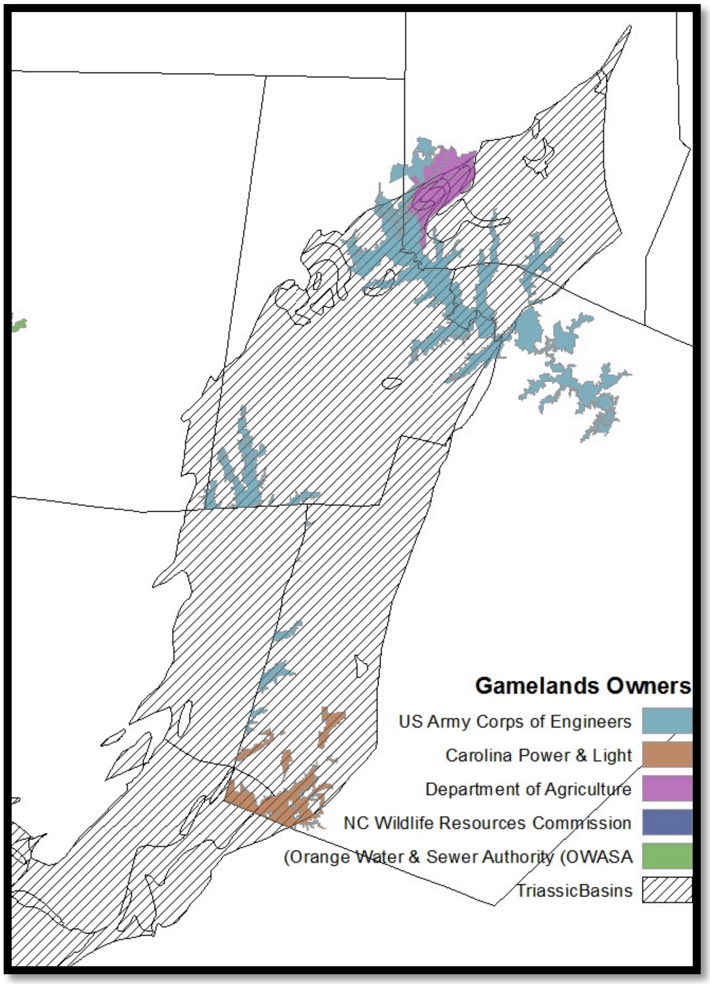
Maps of game lands in the Triassic Basins

Figure 10-16. Dan River Basin and Game Lands



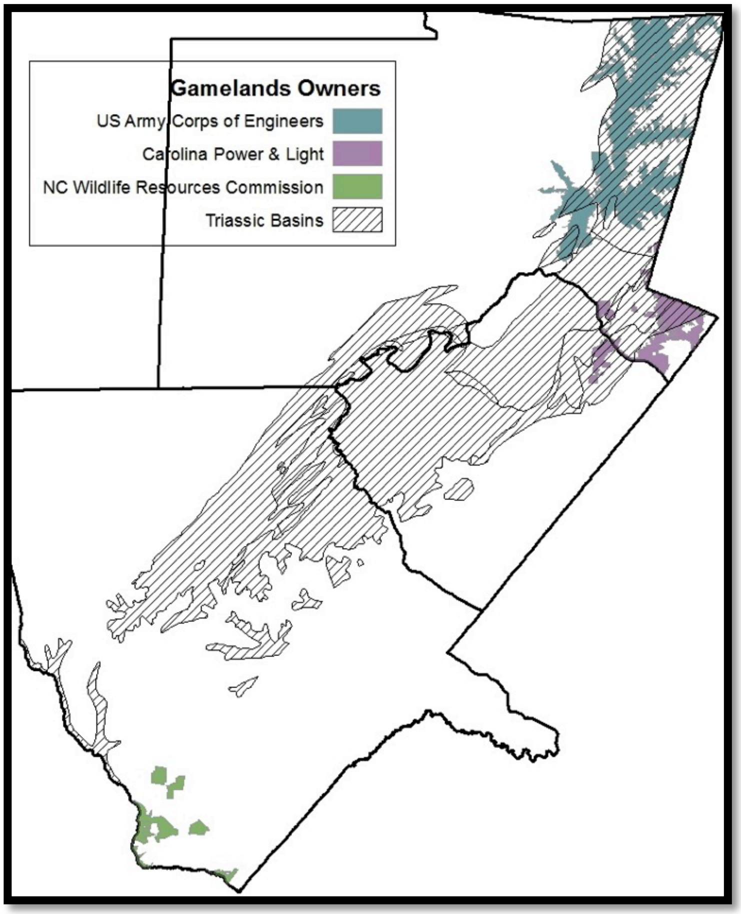
The Triassic Basin shale formation in the Dan River basin does not underlie any game lands.

Figure 10-17. Durham Sub-Basin and Game Lands



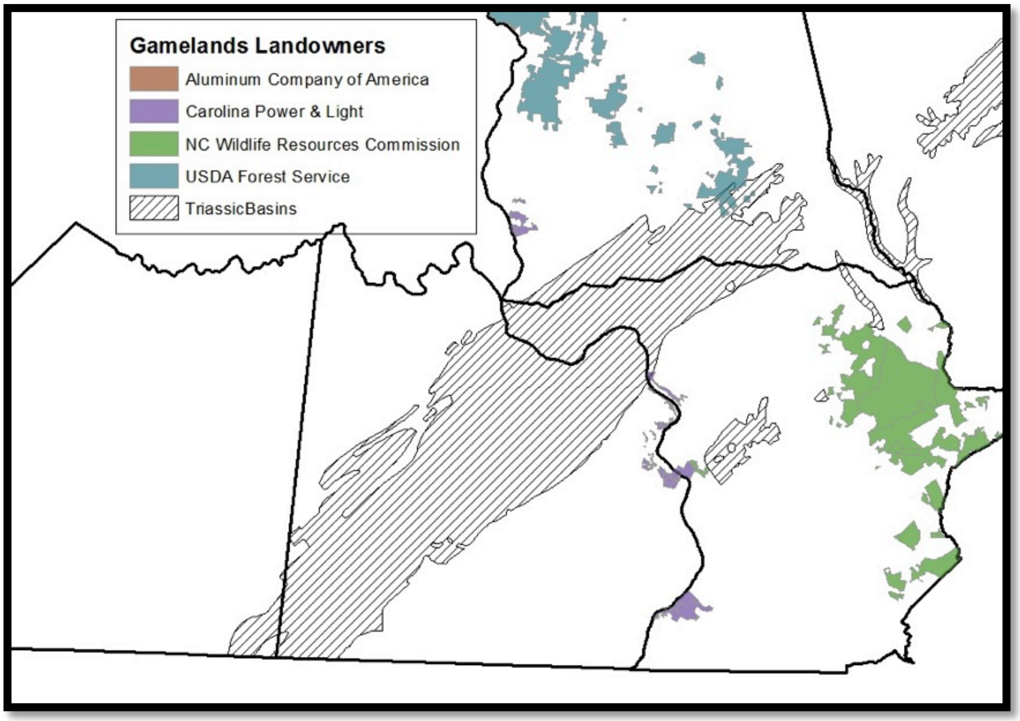
The Triassic Basins shale formation underlies significant portions of game lands in Durham, Wake and Granville counties. Game lands on and around Jordan, Harris and Kerr lakes each have the potential to be impacted if drilling occurs on or nearby the lakes.

Figure 10-18. Sanford Sub-Basin and Game Lands



The Triassic Basins shale formation underlies significant portions of game lands, primarily in the Jordan and Harris Lake regions of Chatham County.

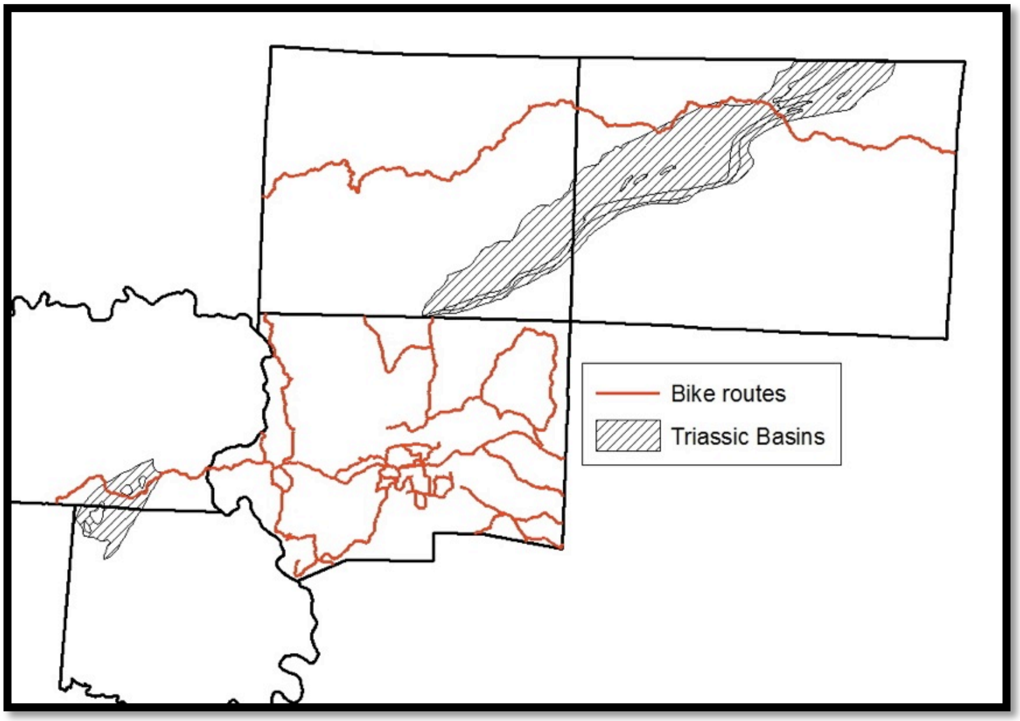
Figure 10-19. Wadesboro Sub-Basin and Game lands



The Triassic Basins shale formation underlies a small portion of game lands in Montgomery and Richmond counties.

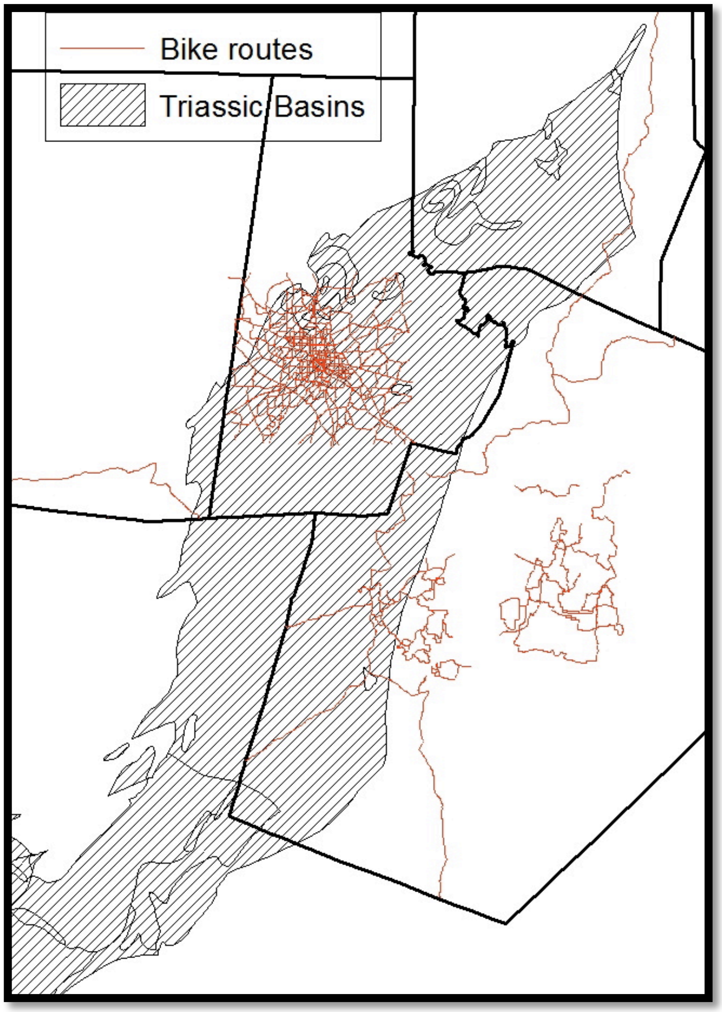
Maps of bike routes in the Triassic Basins

Figure 10-20. Dan River Basin and Bike Routes



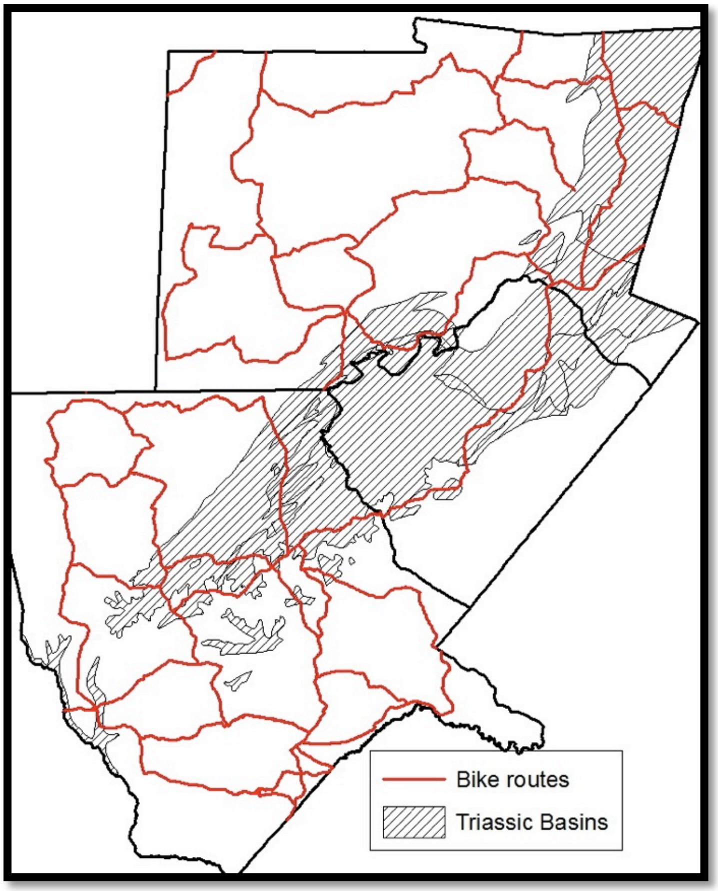
The Triassic Basins shale formations underlie two stretches of bike trail in Rockingham and Yadkin counties.

Figure 10-21. Durham Sub-Basin and Bike Routes



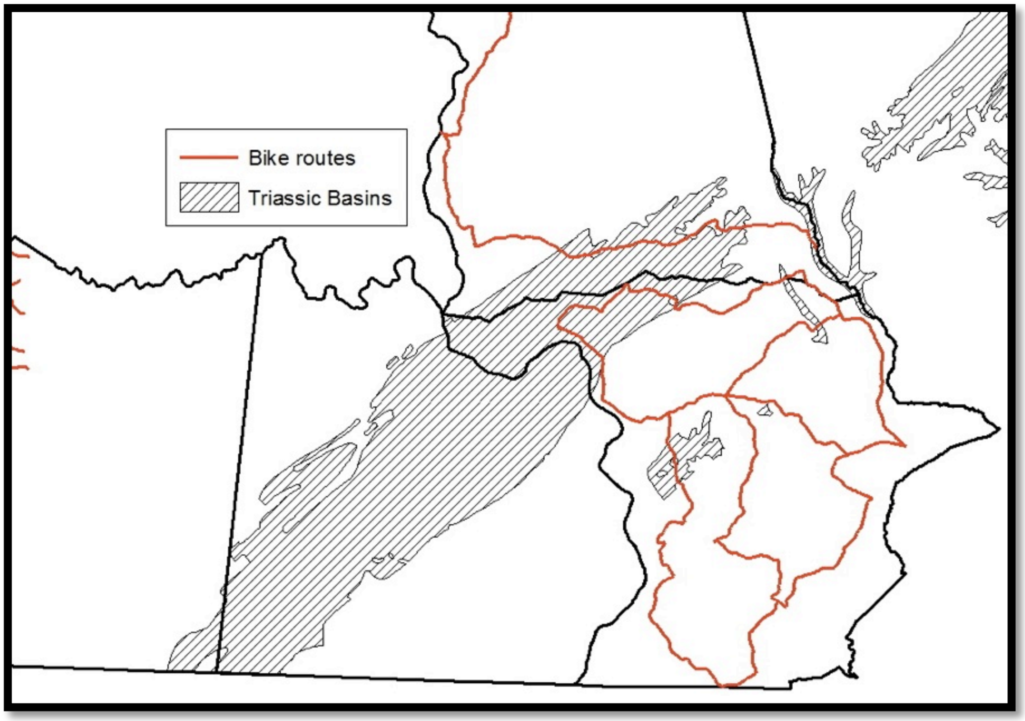
The Triassic Basins shale formation underlies significant portions of bike paths, particularly in Wake and Durham counties.

Figure 10-22. Sanford Sub-Basin and Bike Routes



The Triassic Basins shale formation underlies long stretches of several bike routes in Lee, Chatham and Moore counties.

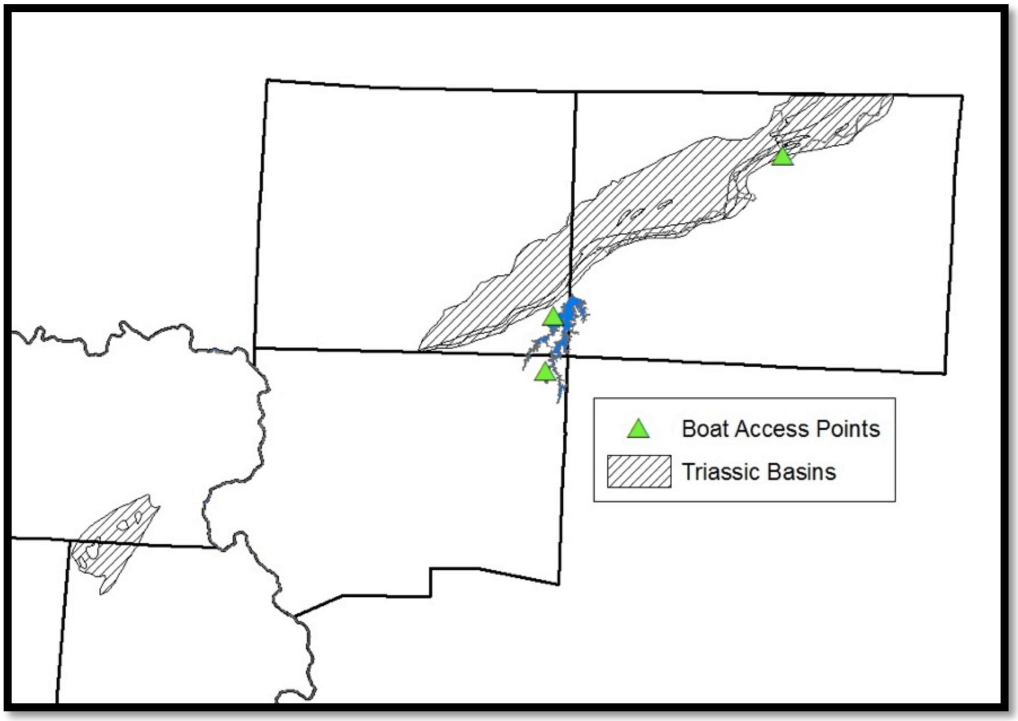
Figure 10-23. Wadesboro Sub-Basin and Bike Routes



The Triassic Basins shale formation underlies several stretches of bike routes in Montgomery and Richmond counties.

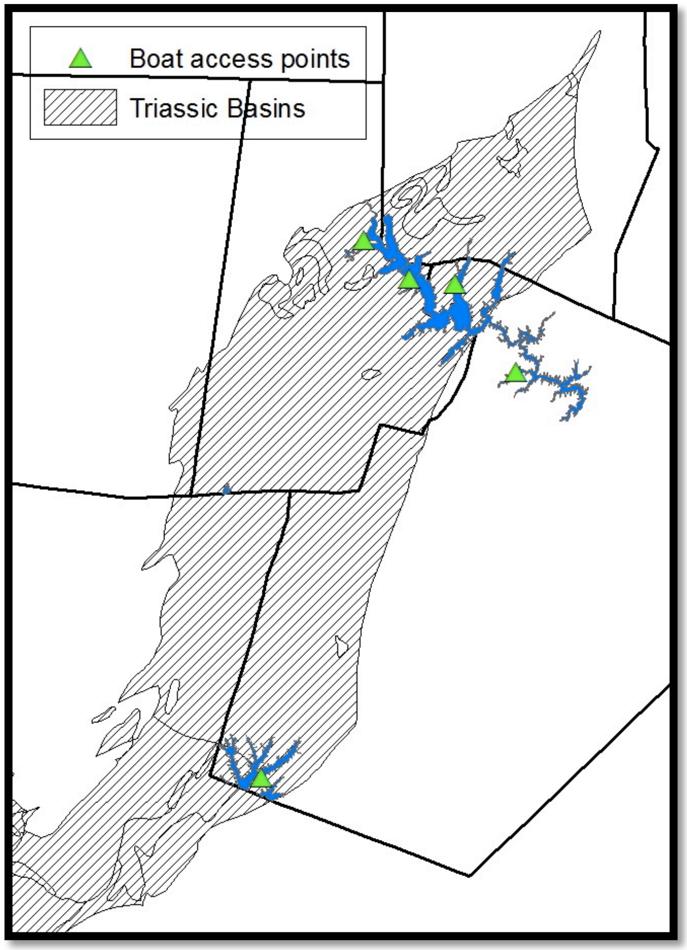
Maps of boat access points and major water bodies in the Triassic Basins

Figure 10-24. Dan River Basin, Boat Access Points and Major Water Bodies



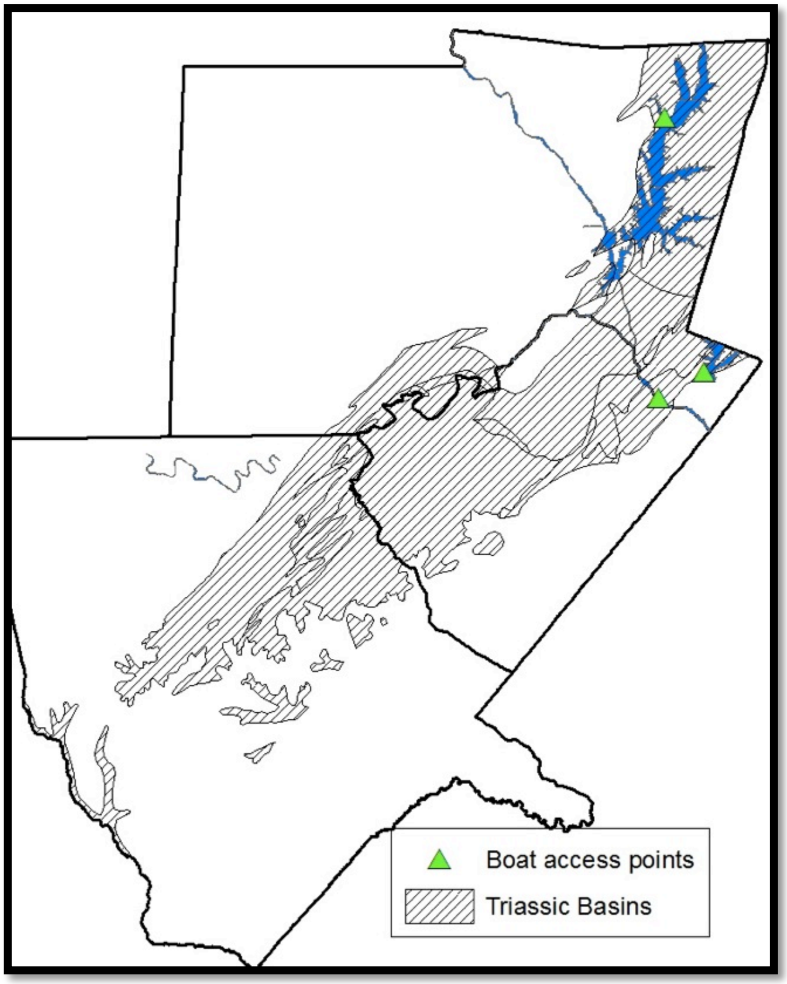
The Triassic Basins shale formation underlies one boat access point on the Dan River in Rockingham County, and lies close to two access points to Belews Lake in Stokes and Forsyth counties.

Figure 10-25. Durham Sub-Basin, Boat Access Points and Major Water Bodies



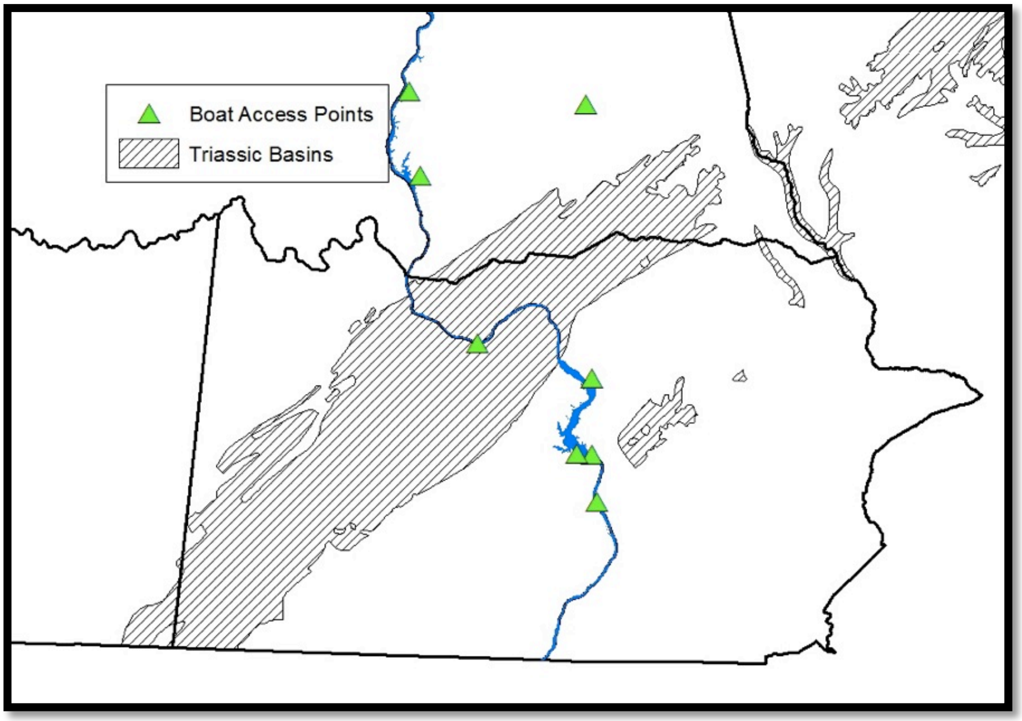
The Triassic Basins shale formation underlies several boat access points in and around Durham, Granville, and Wakes counties. The formation underlies three access points, and lies close to one more, on Falls Lake, in Durham, Granville and Wake counties. The formation also underlies one access point to Harris Lake in Wake County.

Figure 10-26. Sanford Sub-Basin, Boat Access Points and Major Water Bodies



The Triassic Basins shale formation underlies one boat access point on Jordan Lake in Chatham County, one access point on Harris Lake in Chatham County, and one access point to the Deep River on the border of Chatham and Lee counties.

Figure 10-27. Wadesboro Sub-Basin, Boat Access Points and Major Water Bodies



The Triassic Basin shale formation underlies one boat access point on the Pee Dee River, along the border of Anson and Richmond counties. Several other boat access points, located along Blewett Falls Lake and south of Badin Lake, are located nearby the Triassic formation.

Map sources

NC One Map, N.C. DENR, N.C. Geological Survey, NCDOT, Anson County GIS service, Chatham County GIS service, Davie County GIS service, Durham County GIS service, Granville County GIS service, Lee County GIS service, Montgomery County GIS service, Moore County GIS service, Orange County GIS service, Richmond County GIS service, Rockingham County GIS service, Stokes County GIS service, Union County GIS service, Wake County GIS service, Yadkin County GIS service.

C. Appendix C: Common noise sources and levels at 50 feet

Noise Source	Decibel Level
Quiet residential area	40
Electric toothbrush	50-60
Normal conversation	60
Coffee grinder	70-80
Whistling kettle	80
Blender	80-90
Shouted conversation	90
Motorcycle	95-110
Shouting in ear	110
Rock concert	110-120
Stock car race	130
Airplane taking off	140

Source: Center for Hearing and Communication

D. Appendix D: Statistical analysis methodology

Counties included in analysis

North Carolina Deep River Region: Anson, Chatham, Durham, Granville, Lee, Montgomery, Moore, Orange, Richmond, Union, Wake counties

North Carolina Dan River Region: Davie, Rockingham, Stokes, Yadkin counties

Colorado Western Slope Region: Adams, Arapahoe, Archuleta, Baca, Bent, Boulder, Broomfield, Cheyenne, Delta, Dolores, Elbert, Fremont, Garfield, Gunnison, Huerfano, Jackson, Jefferson, Kiowa, Kit Carson, La Plata, Larimer, Las Animas, Lincoln, Logan, Mesa, Moffat, Montezuma, Montrose, Morgan, Phillips, Prowers, Rio Blanco, Routt, San Miguel, Sedgwick, Washington, Weld, Yuma counties.

North Dakota Bakken Region: Adams, Billings, Bottineau, Bowman, Burke, Burleigh, Divide, Dunn, Emmons, Golden Valley, Grant, Hettinger, McHenry, McKenzie, McLean, Mercer, Morton, Mountrail, Oliver, Renville, Sheridan, Sioux, Slope, Stark, Ward, Williams counties.

Oklahoma: all counties.

Pennsylvania Marcellus Region: Allegheny, Armstrong, Beaver, Bedford, Blair, Bradford, Butler, Cambria, Cameron, Centre, Clarion, Clearfield, Clinton, Columbia, Crawford, Elk, Erie, Fayette, Forest, Greene, Huntingdon, Indiana, Jefferson, Lackawanna, Lawrence, Luzerne, Lycoming, McKean, Mercer, Potter, Somerset, Sullivan, Susquehanna, Tioga, Venango, Warren, Washington, Wayne, Westmoreland, Wyoming counties.

Texas Barnett Region: Archer, Bosque, Clay, Comanche, Cooke, Coryell, Dallas, Denton, Eastland, Ellis, Erath, Hamilton, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Shackleford, Somervell, Stephens, Tarrant, Wise counties.

Texas Eagle Ford Region: Atascosa, Bee, Brazos, Burleson, Dewitt, Dimmit, Edwards, Fayette, Frio, Gonzales, Grimes, Houston, Karnes, La Salle, Lavaca, Lee, Leon, Live Oak, Maverick, McMullen, Milam, Webb, Wilson, Wood, Zavala counties.

Wyoming Niobrara Region: Albany, Big Horn, Campbell, Carbon, Converse, Crook, Fremont, Goshen, Hot Springs, Johnson, Laramie, Lincoln, Natrona, Niobrara, Park, Platte, Sheridan, Sublette, Sweetwater, Teton, Uinta, Washakie, Weston counties.

Regression Results

Data were analyzed using county-level data from 2000-2009 or 2000-2010, depending on the availability of the data. Each state was analyzed separately. County level fixed-effects and year level fixed-effects were controlled for, as were population and population density. Other potential controls, including demographic and economic characteristics, were not included due to time and data limitations.

Regressions compared the change in annual oil and gas production per 100,000 people in a given county with assorted crime rates per 100,000 people in that same county each year.

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Table 10-2. Natural Gas Production Changes and Crime Rates per 100,000 People

Crime	Colorado	North Dakota	Oklahoma	Pennsylvania	Barnett	Eagle Ford	Wyoming
Murder	t=-.37 p=.71	-.5 .62	-.20 .85	-.86 .39	-0.66 0.51	-3.66 .0001**	.93 .36
Rape	-.25 .81	-.55 .58	.45 .66	.38 .71	0.35 0.73	.19 .85	.62 .54
Robbery	.53 .60	-.05 .96	-.02 .99	1.67 .10	.38 .70	-.49 .62	.17 .87
Aggravated assault	2.48 .01**	-.46 .64	-.07 .94	.29 .77	-0.64 0.52	-1.60 .11	3.0 .003**
Burglary	1.70 .09	.24 .81	-.24 .81	.96 .34	-2.29 .02*	1.42 .16	-0.84 .40
Larceny/ theft	1.20 .23	-.02 .98	.23 .82	-1.0 .32	-2.73 .007**	-1.50 .14	1.6 .11
Car theft	-.42 .68	.02 .98	-.32 .75	-1.94 .06	-.28 .78	-.63 .53	.07 .94
Violent crime	2.38 .02*	-.45 .66	-.03 .98	.51 .62	-.51 .61	-1.87 .06	3.07 .002**
Non-violent crime	1.55 .12	.26 .79	.15 .88	-.56 .58	-3.57 .0001**	-.76 .45	1.12 .26
Total crime	1.74 .08	-.29 .77	.15 .88	-.23 .82	-.73 .47	-1.12 .27	1.8 .07

*=.95 significance **=.99 significance

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Table 10-3. Oil Production Changes and Crime Rates per 100,000 People

Crime	Colorado	North Dakota	Oklahoma	Barnett	Eagle Ford	Wy
Murder	t=.98 p=.33	-.41 .68	.55 .58	.46 .65	.60 .55	2 .
Rape	-3.62 .0001**	-.80 .42	-.07 .95	-1.29 .20	-1.74 .08	1
Robbery	-.68 .50	-.03 .98	.09 .93	.97 .34	.75 .46	
Aggravated assault	-.83 .41	.04 .96	.15 .88	0.45 0.65	-.46 .64	
Burglary	.81 .42	.14 .89	.48 .63	.22 .82	-1.50 .14	2 .
Larceny/ theft	.03 .98	1.06 .29	-.03 .97	.40 .69	-.72 .47	1
Car theft	-.89 .37	-.26 .80	.37 .72	1.31 .19	.21 .84	1
Violent crime	-1.16 .25	.04 .97	.17 .87	.39 .70	-.46 .65	1 0
Non-violent crime	.17 .86	.31 .75	.11 .92	.96 .34	-1.20 .23	2 .0
Total crime	.32 .75	.44 .66	.13 .90	.37 .72	-1.26 .21	2 .0

*=.95 significance **=.99 significance

Data plots

The X axes of the figures below, “indgaschp100k” or “indoilchp100k” show the change in natural gas production (per thousand cubic feet) or oil production (per barrel) per 100,000 residents in each county and each year of the survey. This figure was chosen because Uniform Crime Reporting data typically shows results in crimes per 100,000 residents. The results are indexed so that the average change in gas or oil production in all the surveyed counties equals the number one. If a given county experienced an increase in gas production in a given year that was 10 times greater than the average change in gas production for all those counties, it receives a value of 10.

The Y axes on the figures below indicate the relevant crime rate per 100,000 residents in a given county, and are also indexed so that the average value is one. If a given county experienced crime rates in one year that were twice the regional average, it receives a score of two.

Figure 10-28. Texas Barnett Region, Index of Change in Gas Production and Index of Nonviolent Crime Rates with Least Fit Squares Line

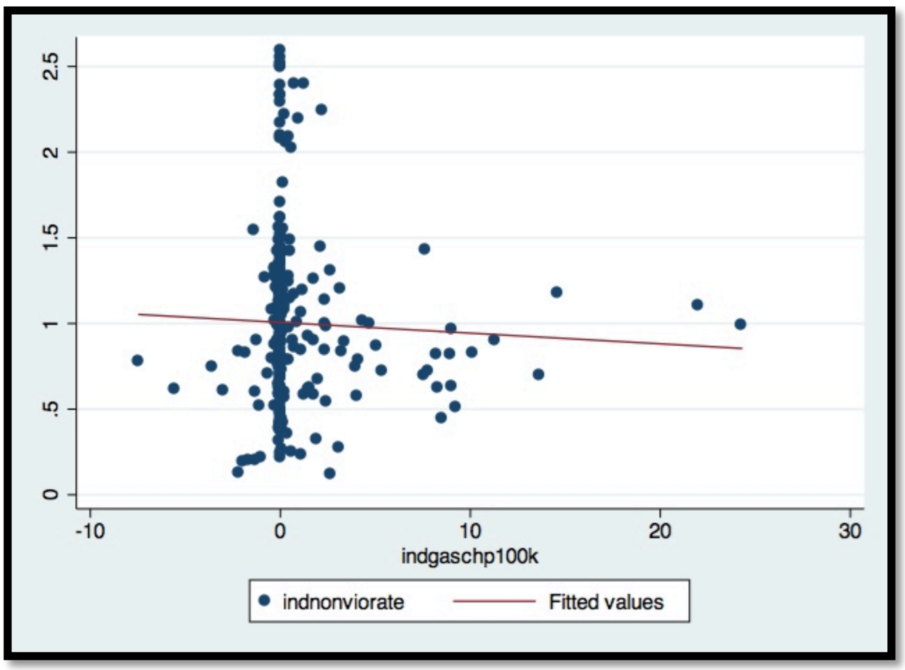


Figure 10-29. Colorado Western Slope Region, Index of Change in Gas Production and Index of Violent Crime Rates with Least Fit Squares Line

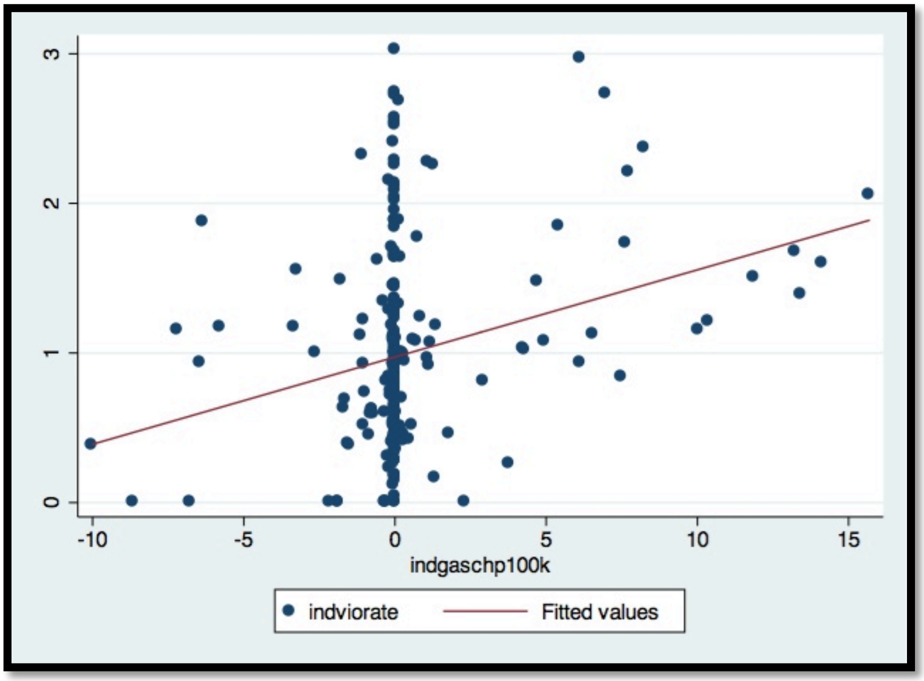


Figure 10-30. Wyoming Green River Basin Region, Index of Change in Gas Production and Index of Violent Crime Rates with Least Fit Squares Line

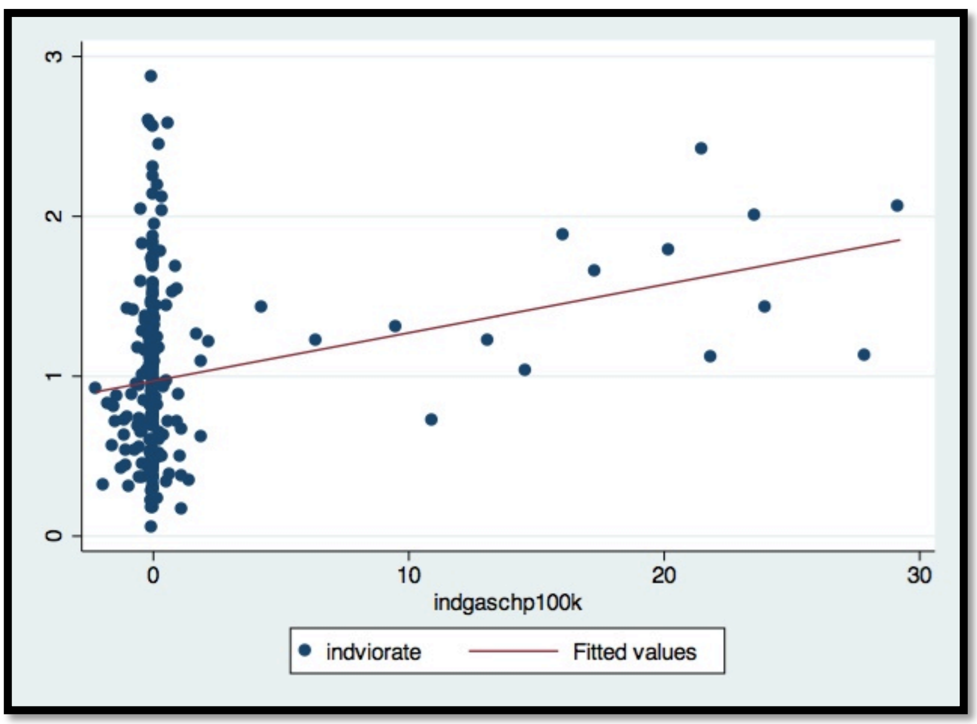
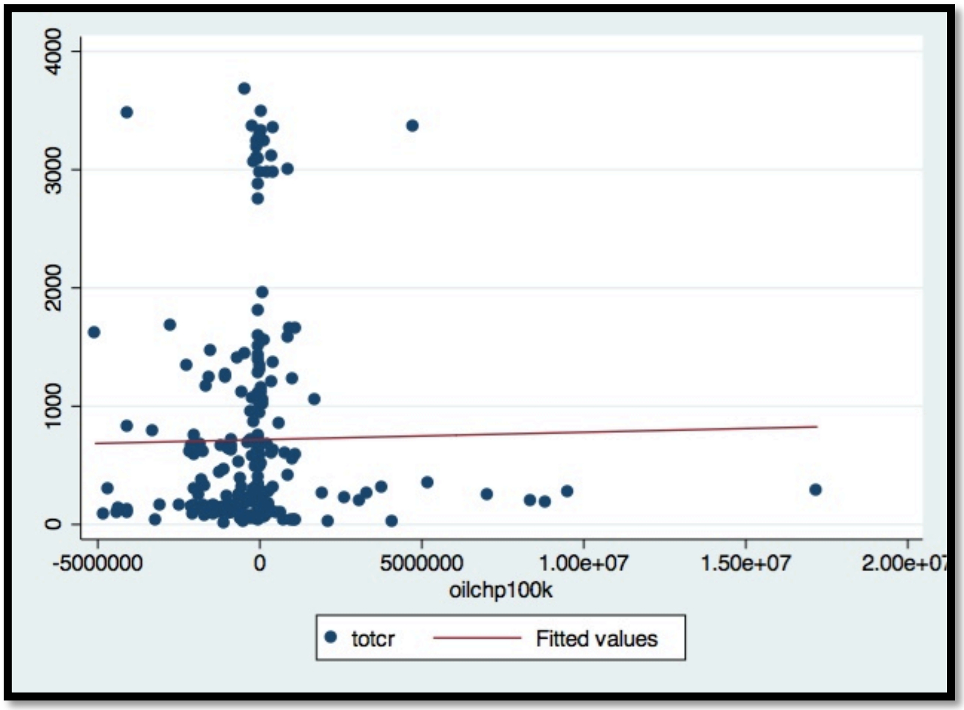


Figure 10-31. Wyoming Green River Basin Region, Index of Change in Oil Production and Index of Total Crime Rates with Least Fit Squares Line



E. Appendix E: STRONGER Report

F. Appendix F: Session Law 2011-276

G. Appendix G: Summary of Public Comments

To be added following public comment period.

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North Carolina Oil and Gas Study under Session Law 2011-276

March 2012

Prepared by the North Carolina Department of Environment and Natural Resources, the North Carolina Department of Commerce, the North Carolina Department of Justice and RAFI-USA

North Carolina State Review

February, 2012

STRONGER
State Review of Oil & Natural Gas Environmental Regulations

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INTRODUCTION

In 1990, the Interstate Oil Compact Commission (IOCC) and the U.S. Environmental Protection Agency (USEPA) jointly published a Study of State Regulation of Oil and Gas Exploration and Production Waste, which contained guidelines for the regulation of oil and gas exploration and production wastes by the IOGCC member states (the "1990 Guidelines"). The published guidelines, developed by state, environmental and industry stakeholders, provided the basis for the State Review Process, a multi-stakeholder review of state exploration and production (E&P) waste management programs against the guidelines. The purposes of the State Review Process are to document the successes of states in regulating E&P wastes and to offer recommendations for program improvement. In 1994, the guidelines were updated and revised (the "1994 Guidelines") by the IOGCC, now named the Interstate Oil and Gas Compact Commission (IOGCC).

In 1999, administration of the State Review Process devolved to a non-profit, multi-stakeholder organization named State Review of Oil and Natural Gas Environmental Regulations, Inc. (STRONGER). STRONGER again revised, expanded and updated the Guidelines, which were accepted by the IOGCC and published in June 2000 as Guidelines for the Review of State Oil and Natural Gas Environmental Regulatory Programs (the "2000 Guidelines"). In 2005 and 2010, STRONGER again revised, expanded and updated the Guidelines (the "2005 Guidelines" and the "2010 Guidelines"). The 2010 Guidelines were used as the basis of this review.

USEPA and the U.S. Department of Energy have provided grant funding to STRONGER to support its activities. The American Petroleum Institute has also provided no-strings attached funding to support the state review process.

In January 2011, the North Carolina Department of Environment and Natural Resources (DENR) volunteered to have its environmental regulatory programs reviewed by STRONGER. In preparation for the review, DENR completed a questionnaire that had been prepared by the STRONGER Board. STRONGER intended the questionnaire to capture the status of the North Carolina program relative to the 2010 Guidelines. The NCDENR prepared a response to the questionnaire, which was sent to the review team.

In October 2011 through January 2012 an eight-person review team appointed by STRONGER conducted a review to evaluate the DENR programs compared to the 2010 Guidelines. The review team consisted of five members and three official observers. The five team members were: Leslie Savage, Railroad Commission of Texas; Don Garvin, Trout Unlimited; Mariel Escobar, independent North Carolina environmental advocate; Bob Sandilos, Chevron; and Chuck Price, BP. The official observer were: Bruce Moore, USEPA; Jim Collins, Independent Petroleum Association of America; and Hope Taylor, Clean Water for North Carolina. Will Morgan, representing the North Carolina Chapter of the Sierra Club, substituted for Ms. Taylor on one of the three days.

The review team conducted a meeting, the in-state portion of the review, in the conference facilities of the DENR in Raleigh, North Carolina on October 24 through 26,

2011. Ms. Robin Smith, Assistant Secretary for the Environment; Dr. Kenneth Taylor, Chief of the North Carolina Geological Survey; Mr. James Simons, State Geologist and Director of the Division of Land Resources; Mr. Evan Kane of the Division of Water Quality; Mr. William Willets of the Air Quality Division; Mr. Kenneth Pickle of the Division of Water Quality; Ms. Helen Cotton of the Hazardous Waste Program in the Division of Waste Management; Mr. Edward Mussler of the Division of Waste Management; and Mr. Thomas Reeder of the Division of Water Resources, all from NCDENR, and Mr. James Albright and Ms. Diana Sulas of the Radiation Protection Section of the North Carolina Department of Health and Human Services (DHHS) presented overviews of their respective program areas and responded to questions from the review team members and official observers. In addition to the North Carolina state employees who participated in the review and the review team, there were forty-eight attendees who observed at least a portion of the review. Following the meeting and after reviewing the written materials provided by the DENR and the DHHS, the review team members compiled this review report.

This is the report of the review of the North Carolina programs against the 2010 Guidelines of STRONGER. Appendix A is a glossary of acronyms used in the report. Appendix B contains North Carolina's written response to the STRONGER questionnaire.

EXECUTIVE SUMMARY

At the invitation of the North Carolina Department of Environment and Natural Resources (DENR), a multi-stakeholder review team has completed an in-depth review of the North Carolina environmental regulatory programs. The review compared the programs against the 2010 Guidelines for the Review of State Oil and Natural Gas Environmental Programs published by STRONGER. During the review of North Carolina's programs, the review team and official observers were granted full access to DENR staff, and all questions were answered in a responsive and open manner.

The review team has concluded that the DENR environmental programs are mature and the staff has significant experience in their various disciplines. However, while the review team recognized strengths in these programs, the review team also has concluded that DENR programs have not been developed in anticipation of the regulation of oil and gas exploration and production activities. Consequently, the findings in this report reflect the comparison of existing programs against the guidelines. The review team recommendations are given to guide the state in the event that it decides to develop an oil and gas regulatory program.

During the discussions with state officials and the review of documents supporting existing programs, the review team determined that several program areas deserve recognition. Those are summarized below.

Program Strengths

I. Mature Environmental Regulatory Programs

North Carolina has mature environmental regulatory programs staffed with experienced professionals. Consequently, North Carolina has experienced, knowledgeable staff and a sound regulatory foundation upon which to build, should the state decide to develop an oil and gas regulatory program.

II. Good Program Coordination

Most of the state's environmental regulatory programs, including the Division of Land Resources, are located in the Department of Environment and Natural Resources. With the exception of the Radiation Protection Section in the Department of Health and Human Services, programs likely to have a significant role in environmental regulation of oil and gas activities fall under the Assistant Secretary for the Environment in DENR. This organizational structure promotes the opportunity to coordinate programs and activities as evidenced during the in-state portion of the review.

III. No Abandoned or Orphan Wells

There have been 128 wells drilled in North Carolina. The first 126 were drilled between 1925 and 1997. Those wells were plugged according to the standards of the day. The two remaining wells, drilled in 1998, remain under permit and bond even though they are not in commercial production. The Division of Land Resources has files and location information on all of the wells.

Program Recommendations

The review team recognizes that North Carolina is evaluating the potential development of its oil and gas resources and is also evaluating changes that may be appropriate if that development were to occur. While this report makes no recommendations on whether or not such development should occur, the review team has made a number of recommendations for consideration **if** that development occurs. A summary of the more important recommendations follows.

I. Need to Develop Formal Standards

The review team found that there are few standards in place that would be applicable to an oil and gas regulatory program. When asked what standards would apply if an operator wanted to drill a well today, the review team was told that existing statutes and rules would be applied on a case-by-case basis.

The review team recognizes that, while this course of action might be workable when only a few permit applications are anticipated, it would not work well if the permit load increased significantly. Additionally, the potential operator and the public, as well as state agency staff, should know with some certainty what the regulatory expectations are before entering the permitting process. Consequently, the review team recommends that, if North Carolina develops an oil and gas regulatory program, formal standards and technical criteria meeting the Guidelines be developed.

II. Potential Need to Develop Oil and Gas Technical Criteria

While North Carolina has mature environmental regulatory programs, the programs have not needed to focus on regulating the impacts of oil and gas development. That may change depending on decisions made by the state. If North Carolina decides to develop an oil and gas regulatory program, that program should contain criteria to address oil and gas related activities, including administrative criteria, technical criteria related to exploration and production waste management, stormwater management, abandoned sites, naturally occurring radioactive materials, and hydraulic fracturing. The review team recommends that, should such a program be developed, the Guidelines be used, along with a review of programs of other states.

III. Potential Use of Stakeholder Groups in Program Development

The Department of Environment and Natural Resources generally involves stakeholder groups early in discussions of proposed rules that involve major policy changes or are the subject of significant public interest.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the Department of Environment and Natural Resources continue to use independent scientific advisory groups, local advisory committees, groups of government, public and industry representatives, or other similar mechanisms, to obtain input and feedback in the development of the program.

PROGRAM OVERVIEW

Oil and gas production does not occur in North Carolina at this time. However, between 1925 and 1997, 126 oil and gas wells were drilled in the state. None of the wells produced commercial quantities of oil and gas, and all were plugged according to the standards of the day.

More recently, exploration in Lee and Chatham counties in central North Carolina has given rise to the anticipation of potential shale gas production from the Dan River and Deep River basins. Two exploration wells drilled in 1998 remain under permit and bond, but are not in production. Four companies have leased more than 9,000 acres in the Lee County area. A report by the U.S. Geological Survey assessing the shale formations in the Deep River and Dan River Basins is expected to be released in 2012.

I. GENERAL CRITERIA

The Department of Environment and Natural Resources (DENR) is the agency with primary responsibility for the regulation of oil and gas exploration and production in North Carolina. Within the Department, the Division of Land Resources (DLR) has lead responsibility for the evaluation and exploration of natural gas resources. Other programs, including the Divisions of Water Quality (DWQ), Waste Management (DWM), Air Quality (DAQ), and Water Resources (DWR), share portions of this responsibility for activities that fall within their jurisdictions. These divisions are all under the supervision of the Assistant Secretary for Environment.

Statutory Authority

Oil and gas activities regulated by DENR are conducted under the authority of the Well Construction Act (DWQ), the Oil and Gas Conservation Act (DLR), the Water and Air Resources Act (DAQ, DWR, DWQ), the Air Pollution Control Act (DAQ), the Oil Pollution and Hazardous Substances Control Act (DWM), and the Solid Waste Act (DWM). All of these statutes provide authority to promulgate rules and regulations.

The DLR has the authority to approve, deny, or revoke oil and gas permits. DAQ, DWQ and DWM have similar authority for permits issued under their jurisdictions. All of these programs have authority to assess civil penalties and to seek injunctions against violators. The Division of Waste Management also has the authority to issue administrative orders for compliance. In the case of particularly egregious violations, the divisions may also pursue a criminal enforcement action through the district attorney of the county where the violation occurred.

The Radiation Protection Section in the Division of Health Service Regulation within the Department of Health and Human Services has limited responsibilities relating to oil and gas. Its activities are conducted under the authority of the Radiation Protection Act.

The Oil and Gas Conservation Act (G.S. 113, Article 27) authorizes DENR to process applications to drill, regulate related activities, assess fees, protect landowners, prevent waste, limit production and regulate well construction, abandonment and plugging. The Act also provides authority to penalize operators who do not comply with the regulations. A rule adopted pursuant to the Oil and Gas Conservation Act, 15A NCAC 05D.0107, DRILLING AND COMPLETION, specifies that no well should be constructed that has a vertical variance greater than three degrees from top to bottom.

The Well Construction Act (G.S. 87, Article 7) provides for the regulation of well construction. Oil and gas operators seeking a permit to drill a well must obtain DWQ approval based on a case-by-case assessment of the well construction plan before a drilling permit will be issued by DLR.

The Division of Water Resources regulations require registration of water withdrawals of more than 100,000 gallons of water per day under the Water and Air Resources Act (N.C.G.S. 1`43, Article 21). The Water and Air Resources Act also provides statutory authority to regulate storm water. In addition, the Water and Air Resources Act prohibits the disposal of water in wells. Rules adopted pursuant to the statute prohibit the initiation and propagation of fractures by injection. DENR currently interprets these statutes and rules to prohibit underground waste disposal and hydraulic fracturing.

North Carolina has received primary enforcement responsibility under the federal Resources Conservation and Recovery Act, Clean Air Act, Clean Water Act and Safe Drinking Water Act (including the Underground Injection Control program). Many environmental standards in North Carolina are equivalent to those set by the USEPA.

Rules and Regulations

In North Carolina, most environmental rules are adopted by citizen boards and commissions. The Environmental Management Commission (EMC), which acts independently, but is organized under DENR, has authority and responsibility to promulgate rules safeguarding water and air resources of the state. EMC members represent all regions of North Carolina; appointments to the 19-member Commission are divided among the Governor, the Senate President Pro-Tempore, and the Speaker of the House. The Commission for Public Health (organized under the Department of Health and Human Resources) has responsibility for rules related to solid and hazardous waste.

A standing Scientific Advisory Board (SAB), whose members are appointed by the Secretary of DENR, advises the EMC in determining concentrations of acceptable ambient levels (AAL) of toxic air emissions within the state. AAL evaluations are made on a chemical-by-chemical basis, and are used by the DAQ and EMC in developing related rules.

The North Carolina Administrative Procedures Act (APA) recognizes three classes of rules. Emergency rules can be adopted without public notification or comment, but may only be adopted in response to "…public health and safety…" emergencies. Temporary rules and permanent rules require public notice, public hearings, and a 30-day period for comment. Once adopted, the Rules Review Commission (RRC) reviews the rule for clarity, necessity, statutory authority and compliance with APA rulemaking procedures. As part of the RRC process, the APA allows members of the public to submit letters of objection to a rule. If ten (10) or more people file objection letters with the RRC, the rule cannot go into effect until the legislature has had a chance to review the rule. The legislature can disapprove the rule, enact legislation that has the effect of changing some or all of the policy decisions set out in the rule, or allow the rule to go into effect. The APA sets specific timelines for legislative action; if the legislature fails to take action within the time allowed, the rule goes into effect as originally adopted. The APA has recently been amended to place additional restrictions on adoption of environmental rules that are more stringent than federal standards.

The Governor has authority to create Executive Orders; an Executive Order cannot override a statute. Under the APA, the Governor may use an Executive Order to put a rule into effect immediately – even though 10 people have objected to the rule – if the Governor finds it to be in the public interest. This kind of Executive Order allows an new rule to go into effect and remain in effect until the legislature disapproves the rule or until the rule would normally go into effect based on the legislature's failure to act.

Funding and Staffing

As there is no active oil and gas production activity in the state, the DENR currently has no full-time staff members working on oil and natural gas permitting and regulation. In recent years, budget cuts have reduced the number of field inspectors in the Division of Land Resources. The water, air, and waste programs have also lost staff positions due to the economic downturn and resulting loss of tax revenue.

DENR has divided the state into seven regions, with division field staff assigned to the various regional offices. Regional inspectors have authority to assess fines and penalties and initiate penalties for erosion and sedimentation permit violations. DENR programs assign regional office staff based on the nature and volume of each county's potential shale gas resources. These offices have not been staffed to handle an additional workload associated with natural gas exploration and development.

House Bill (HB) 242, Session Law 2011-276 mandates among other things that DENR, in conjunction with the North Carolina Department of Consumer Protection Section of the State Attorney General's Office, study potential oil and gas exploration and development in North Carolina. The bill specifically directs the Department to study the use of horizontal drilling and hydraulic fracturing for natural gas development and the potential impacts of these activities. The DENR is gathering information and public input. A report containing the DENR's findings and recommendations is due to the legislature by May 1, 2012.

Finding I.1.

North Carolina has mature environmental protection and regulatory programs staffed with experienced professionals.

Finding I.2.

All DENR Divisions with current jurisdiction over oil and gas E&P activities are under the supervision of the Assistant Secretary for Environmental Protection. This promotes cooperation and coordination between the programs.

Finding I.3.

Air toxics regulated by North Carolina include benzene as well as hydrogen sulfide and other potential constituents of air emissions from oil and gas operations. Air quality standards go beyond those promulgated by the USEPA.

II. ADMINISTRATIVE CRITERIA

Basic Requirements

DENR has been delegated primary enforcement authority for various federal programs, including the federal Clean Air Act, the Resource Conservation and Recovery Act (Solid Waste), the Clean Water Act (for National Pollutant Discharge Elimination System Permits), and the Safe Drinking Water Act (Underground Injection Control Program for injection wells in Classes I-V). The state has basically adopted and enforces the federal regulations, although there are some state-specific programs and requirements. Although a number of these requirements may affect oil and gas activity, very few are specific to these activities. These programs include provisions for permitting, compliance evaluation, and enforcement.

Permitting

For oil and gas permits, the applicant must register, provide a bond, and apply for a drilling permit. An application for permit to drill an oil or gas well triggers a series of other permits, which must be obtained prior to the issuance of a drilling permit. The applicant is required to submit a site plan describing where the drilling is proposed, the proposed depth of the well, the casing and cementing specifications, and the plan for on-site storage of water, wastewater and mud in pits and/or tanks. When the Division of Land Resources receives the drilling permit application, the information is shared with other DENR divisions to identify other issues that must be addressed. The drilling permit is the master permit; an applicant must obtain other state approvals, including a well construction permit, before a drilling permit can be issued. In addition, a sedimentation and erosion control plan is required if more than one acre of land is disturbed (including any access road to the site). The plan must include measures for controlling sediment during land-clearing, grading and construction, and a plan for restoring the site after land-disturbing activity has been completed. Air quality permitting may be required for some oil and gas operations.

The DENR includes conditions in the drilling permit to address site location, endangered or threatened wildlife species, off-site runoff, waste management, inspections and notification. The DENR has the ability to include any conditions it deems necessary within its authority.

The DENR has regulatory mechanisms to assure that wastes are managed in an environmentally responsible manner, however, the programs are not specific to E&P operations. State law defines “solid waste” to include both hazardous and non-hazardous waste, but the definition excludes oils and other liquid hydrocarbons. The definition of solid waste includes the non-oil components of E&P such as the drilling muds and cuttings. Solid wastes that are not RCRA hazardous wastes may go into an industrial landfill that is designed and constructed for that particular waste or may go to a municipal solid waste (MSW) landfill. North Carolina has strong standards for design and construction of industrial and MSW landfills, but those standards were not developed to address disposal of RCRA hazardous waste. E&P wastes include some wastes that have the characteristics of RCRA hazardous waste, but are not regulated under RCRA because of the RCRA exclusion for E&P wastes. North Carolina does not specifically address disposal of those types of waste.

Without statute or rule changes, all E&P wastes (other than oils and liquid hydrocarbons) that are not classified as RCRA hazardous waste could legally go to a MSW landfill. The landfill operator can exclude wastes otherwise allowed for disposal, however. Wastes that are difficult to handle or that would pose an unusual risk may be turned away.

DENR programs include issuance of individual permits, generally on a case-by-case basis, and registration of operators and facilities. The DENR has the authority to refuse to issue or reissue permits or authorizations. Authority to consider the applicant's outstanding violations, unpaid penalties and past compliance history as factors in permitting varies somewhat among the different DENR regulatory programs. The DENR requires that the applicant comply with federal, local, or other state permits or regulatory requirements.

If DENR refuses to issue or reissue a permit or authorization, state law allows the applicant to appeal the decision by filing a petition for an administrative hearing under General Statute 150B-23, which is part of the state's Administrative Procedures Act. The time allowed for filing the petition may vary, however, from program to program. N.C.G.S. 150B-23 establishes a basic 60-day period (after receipt of the agency decision), but recognizes that other statutes may set different time periods for individual regulatory programs. The Oil and Gas Act allows only 10 days to appeal a decision or order issued under that Act. For water and air quality permits, a petition must be filed within 30 days after the applicant receives the decision.

The DENR issues individual permits for specific facilities or operations for fixed terms, generally five or less years, but in some instances eight years. The DENR programs and processing procedures ensure that, where similar requirements are mandated by two or more regulatory programs, those requirements are combined where feasible.

The DENR has an Environmental Permit Assistance program, whose stated purpose is to provide technical assistance and guidance through regulatory, permitting and compliance processes and to reduce overall environmental impacts. The center has staff representatives across the state and serves as a single point of contact for its customers and a liaison between the customer and the regulatory agencies.

Finding II.1.

The Review Team commends the DENR for its Environmental Permit Assistance Program.

Finding II.2.

The DLR has handled the very small number of oil and gas permits previously issued in the state on a case-by-case basis and coordinated review of those permit applications with other DENR divisions, as necessary. Handling of permit applications in such a manner allows the agencies to consider all aspects of an application and tailor the permit conditions. Such processing is admirable for the management of a small number of facilities.

Recommendation II.2.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR adopt more detailed standards and criteria for the potentially large number of permit applications that might be expected during periods of high oil and gas activity to ensure consistency and efficient permit application processing and to provide the regulated industry and the public with an understanding of the standards and criteria that will be used by the agency in reviewing and processing applications. (2010 STRONGER Guidelines, Section 4.1.1. and Section 5.)

Compliance Evaluation

The DENR programs have the authority to carry out inspections and investigations, enter property, examine records, and collect evidence. The DENR has the capability to conduct comprehensive investigations of facilities and activities subject to regulation in order to identify a failure to comply with program requirements by responsible persons.

The DENR has the authority to conduct regular inspections of regulated facilities and activities at a frequency that is commensurate with the risk to the environment that is presented by each facility or activity.

The DENR has the authority and procedures to investigate information obtained from inspections or complaints regarding violations of applicable program and permit requirements. Inspections are prioritized based on risk and may be unannounced. DENR staff has the authority to enter locations where records are kept during reasonable hours for purposes of copying and inspecting the records.

Generally, each DENR regulatory program coordinates the preparation and filing of formal enforcement actions through its headquarters office. Appeals of civil penalty assessments are handled by the Office of Administrative Hearings.

Finding II.3.

Recent state budget issues have impacted the DENR's ability to perform inspections in certain program areas.

Recommendation II.3.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the state provide the DENR with funding adequate to effectively and efficiently perform compliance evaluation of oil and gas activities for the protection of human health and the environment. (2010 STRONGER Guidelines, Section 4.1.2.)

Enforcement

The DENR has enforcement tools, including the authority to issue a notice of violation with a compliance schedule; issue cease and desist orders; revoke, modify, and suspend permits; assess administrative penalties; cause forfeiture of financial assurance instruments; and obtain injunctions. In addition, the DENR has the authority to identify emergency conditions that pose an imminent and substantial human health or environmental hazard that would warrant entry and immediate corrective action by the DENR after reasonable efforts to notify the operator have failed, and to seek reimbursement of the state's costs. State statutes provide the DENR with enforcement authority in the form of civil and criminal penalties, and injunctive relief.

Maximum penalty amounts are set in state statute. N.C. General Statute 113-410 sets penalties for violations of the Oil and Gas Conservation Act. Other DENR regulatory programs (such as water quality, air quality, and solid waste) have similar statutory provisions setting the maximum penalty for an individual violation of those requirements. The statutes also authorize the assessment of daily penalties for continuing violations. Most DENR divisions use a penalty tree to calculate civil penalties for violations of the statutes and rules; however, DENR staff could not remember ever having assessed the maximum penalty for a violation. In assessing penalties, the DENR considers statutory factors including economic benefit resulting from the violation, willfulness, harm to the environment and the public, harm to the ecosystem, and expenses incurred by the state in response and cleanup. N.C.G.S. 143B-282.1 specifically allows consideration of the responsible party's compliance history in determining the amount of a penalty for an air quality or water quality violation. The Oil and Gas Conservation Act does not identify factors to be considered in setting the amount of a penalty for violations of its requirements and simply sets the maximum daily penalty for a single violation at $1,000.

North Carolina's statutes afford the opportunity to appeal or seek administrative and/or judicial review of agency action.

Finding II.4.

The DENR has the necessary enforcement authority consistent with 4.1.3. of the Guidelines.

Recommendation II.4.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR evaluate their enforcement options and policies to assure that the full range of actions available are effectively used to provide compliance incentives for oil and gas activities and adequate to act as a disincentive to non-compliance. (2010 STRONGER Guidelines, Section 4.1.3.)

Contingency Planning and Spill Risk Management

North Carolina has an integrated Emergency Management Program (EMP). State regulations incorporate by reference 40 CFR 264, which is intended for treatment, storage, and disposal of hazardous waste by injection under the federal Resource Conservation and Control Act (RCRA) but serves as the comprehensive template for statewide contingency plan requirements. The State Emergency Operations Plan (SEOP), which lists the hazardous materials plan, includes the response to hazardous materials, suspected hazardous materials and unknowns. North Carolina has a well-defined SEOP and coordinates effectively with USEPA Region IV through the Raleigh office, and through joint action as described below.

The North Carolina EMP is funded by general revenue, which also is available to meet competing s tate government needs. North Carolina calls upon the USEPA Emergency Response Program to mobilize federal contractors to assist in the response to and remediation of spills as part of the National Contingency Plan, but Federal Emergency Management Agency (FEMA), hazardous materials (HAZMAT), and other federal emergency response funding also is being reduced.

Finding II.5.

The North Carolina State Contingency Plan does not contain criteria for spill response or responsibilities specific to E&P.

Recommendation II.5.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, North Carolina develop E&P-specific contingency plan response criteria and responsibilities. (2010 STRONGER Guidelines, Section 4.2.1.1.)

Finding II.6.

North Carolina does not receive any funding for state contingency or spill response program activities from the oil and gas industry.

Recommendation II.6.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, North Carolina consider development of a plan and incentive for E&P operators to directly fund any critical shortfalls in local direct emergency response and spill prevention capability. (2010 STRONGER Guidelines, Section 4.2.1.1.)

Finding II.7.

The DENR has reduced staff recently due to budget reductions.

Recommendation II.7.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, maintaining staff at a level to provide effective and E&P-specific SEOP capability should be a top priority. (2010 STRONGER Guidelines, Section 4.2.1.1.)

Personnel at the State Emergency Operations Center receive reports related to emergencies. The center is staffed 24 hours a day, 7 days a week. Their telephone number is 1-800-858-0368. In addition, operators or members of the public can contact local emergency services by dialing 911 or by calling the National Response Center. The state maintains seven regional HAZMAT teams.

Finding II.8.

The state maintains effective reporting capability.

Finding II.9.

The state maintains effective interagency coordination within the DENR Divisions. Interagency coordination is described in the state EOP and represents effective integration of USEPA and local LEPC roles and capabilities. The DENR Divisions communicate effectively with each other and with NC DPS on emergency response issues, but roles and responsibilities are diversified.

Recommendation II.9.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR, DPS and affected local LEPC/ first responders should develop a Memorandum of Understanding (MOU) concerning E&P activities. The review team further recommends that the state post the EOC Call Center responsibilities for E&P activities online for operators new to the state. (2010 STRONGER Guidelines, Section 4.2.1.3.)

Finding II.10.

Although a site-specific contingency plan may be required as a binding condition of the permit to drill, E&P-specific requirements do not exist.

Recommendation II.10.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the state should adopt and communicate spill prevention and response guidance for E&P operators consistent with API and other industry best practices and standards. The review team further recommends that the state provide for any necessary specialized training and equipment resources consistent with activity and risks associated with oil and gas E&P operations. (2010 STRONGER Guidelines, Section 4.2.1.4.)

Finding II.11.

The state maintains a one-call response center as discussed above. Response measures may be specified as permit conditions, but the state has no adopted minimum E&P-specific prevention measures. The EPA Region IV office in Raleigh maintains responsibility for enforcing the SPCC program, and is a resource on measures specific to upstream oil spill prevention.

Recommendation II.11.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the state develop and adopt guidance relating to planning for and meeting state spill prevention permit conditions. (2010 STRONGER Guidelines, Section 4.2.1.4.2.)

Finding II.12.

State Groundwater Classifications and Standards include general response requirements for corrective action, but these requirements apply only to spills “where groundwater quality has been degraded” and addresses spills to soil only in the context of hazardous waste requirements.

Recommendation II.12.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the state develop and communicate operator corrective action guidance specific to spills of RCRA Subtitle C-exempt E&P wastes, consistent with regulations and risk-based best practices. (2010 STRONGER Guidelines, Section 4.2.1.4.3.)

Finding II.13.

The state EOP outlines reporting, monitoring, and approvals, which are also addressed in regulations. The regulations apply only to spills "where groundwater quality has been degraded" and addresses spills to soil only in the context of hazardous waste requirements.

Recommendation II.13.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the state develop and communicate reporting, monitoring and approval guidance specific to spills of RCRA-exempt E&P wastes. The review team further recommends that the DLR and DWM determine primary responsibilities for E&P spill prevention and response and provide on-line access to spill prevention and response information. The review team further recommends that the state develop and make available to industry an incident review process for determining causation and future prevention measures suitable for E&P operations. (2010 STRONGER Guidelines, Section 4.2.1.4.3.)

Finding II.14.

The state EOP, which outlines general enforcement, damage assessment, responsible party, and reimbursement requirements applicable to E&P operations, meets the guidelines for follow-up action.

Finding II.15.

The state EOP outlines reporting and database requirements; however, the review team could not determine whether the plan includes a provision for periodic analysis of spills and releases, or if this will occur on an as-needed basis.

Public Participation

The DENR requires public notice for some activities for which it requires a permit. Public notice is not the same for all activities, but is determined by the magnitude of the proposed activity and the public interest in the proposed activity. However, notice requirements are not specific to oil and gas permitting.

The state's rulemaking process can take two or more years. Although the state's administrative procedures allow for emergency rulemaking when required by a "serious and unforeseen threat to the public health or safety," the statutes do not provide for emergency rulemaking to address a threat to public welfare.

In addition, DENR staff generally involves stakeholder groups early in discussions of rulemaking activities that involve major changes and/or are the subject of great public interest.

Finding II.16.

The DENR uses stakeholder groups early in the rulemaking process to help it formulate draft rules.

Recommendation II.16.

The Review Team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR establish public notice requirements for oil and gas activities and permits because notification to the public and landowners is critical to assuring accountability. (2010 STRONGER Guidelines, Section 4.2.2.1.)

General Statute Chapter 132 defines public records and establishes the requirements for their availability to the public. All public records are available for review at the DENR offices.

Finding II.17.

The DENR meets Section 4.2.2.1. of the Guidelines with respect to public records.

The DENR has outreach programs to educate the regulated industry and the public about its air, hazardous waste, and stormwater programs.

The DENR held a public meeting (which was also webcast) on the shale gas study mandated by Session Law 2011-242 in early October of this year in the area of potential interest (Sanford, N.C.). The purpose of the public meeting was to receive public comments on the draft outline for the study. The Department also accepted written comments. The DENR plans at least one more public meeting in the spring to gather input on the initial draft of the study report.

Finding II.18.

None of the DENR's public education and outreach programs relate to oil and gas activities.

Recommendation II.18.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR develop education and outreach programs for operators and the public for oil and gas activities. (2010 STRONGER Guidelines, Section 4.2.2.2.)

The DENR uses an independent Science Advisory Committee to aid it in determining program requirements. In addition, the DENR uses stakeholder groups early in the rulemaking process.

Furthermore, a small group of legal, scientific and technical experts will be asked to serve as advisors on the shale gas study mandated by Session Law 2011-276 (House Bill 242). This group will include people with expertise in local government law, environmental law and policy, energy development, hydrology, geology, and economic development. Advisors also will include representatives from the Department of Commerce, the Consumer Protection Division of the North Carolina Attorney General's Office, and the Rural Advancement Foundation International.

Finding II.19.

The review team commends the DENR for using advisory groups, particularly the independent Science Advisory Committee and the advisors with specific expertise related to the shale gas study.

Recommendation II.19.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR continue to use advisory groups of industry, government, and public representatives, or other similar mechanisms, to obtain input and feedback in the development of and the state programs for the management of E&P wastes. (2010 STRONGER Guidelines, Section 4.2.2.3.)

Program Planning and Evaluation

The DENR performs strategic planning periodically to identify issues and define goals and objectives, set priorities, and evaluate the clarity, efficiency, and effectiveness of its programs.

The 2009-2013 strategic plan states the DENR's mission and values and its goals for DENR programs over the coming years. The DENR's primary mission is to "conserve and protect North Carolina's natural resources and to maintain an environment of high quality by providing valuable services that consistently support and benefit the health and economic well-being of all citizens of our state". The plan includes actions such as "Improve the state's response to groundwater contamination incidents through improved coordination among state agencies and local governments, stronger enforcement policies, and increased public education." The latest strategic plan states that the DENR should "continue and support the evaluation and exploration of natural gas resources in the state."

Finding II.20.

The review team commends the DENR for including discussion of natural gas development in its latest strategic plan.

Recommendation II.20.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR include oil and gas activities in its strategic planning. (2010 STRONGER Guidelines, Section 4.2.3.1.)

Finding II.21.

The DENR publishes a "State of the Environment" report every 2 years. The latest report (2011) includes discussion of the issues the DENR faces, including the emerging issue of potential shale gas exploration and development, and outlines the DENR's plans to address those issues.

Recommendation II.21.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR obtain an environmental baseline and develop a process for continually evaluating how well the oil and gas program protects human health and the environment. (2010 STRONGER Guidelines, Section 4.2.3.2.)

Financial Assurance

Prior to drilling an exploratory well for oil or gas, current statutes require an operator to secure up-front financial assurance in the form of a bond in the amount of $5,000 plus $1 per foot of depth to ensure that wells are properly plugged. However, there are no statutory or regulatory requirements for financial assurance for other activities, such as land application of waste, site reclamation and closure, or remediation of environmental damage (such as soil or groundwater contamination). Since the bond amount is set by statute, the DENR does not have authority to expand bonding requirements or update bond amounts without additional legislative action.

Finding II.22.

The DENR does not have specific statutory or regulatory requirements relating to financial assurance for oil and gas activities other than bonding to ensure the proper plugging of an oil or gas well. Existing statutory authority would not allow the DENR to require a bond sufficient to cover site reclamation and closure or remediation of contamination.

Recommendation II.22.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the state give the DENR the authority to require additional financial assurance for site remediation, closure and remediation, to determine the form of the financial assurance, to set the amount of the financial assurance based on potential risk, and to access financial assurance when an operator fails to meet its obligations covered by the financial assurance instrument. (2010 STRONGER Guidelines, Section 4.2.4.)

Recommendation II.23.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR periodically review the amount of required financial assurance to determine if the amount is adequate to provide incentive for proper plugging of a well and reclamation of a site, and to assure proper management of E&P wastes. (2010 STRONGER Guidelines, Section 4.2.4.)

Waste Hauler Certification

Finding II.24.

The DENR does not require certification or permitting of waste haulers or registration of vehicles. Solid waste regulations require manifesting of wastes consistent with federal requirements. Manifests must be available on site.

Recommendation II.24.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR consider a certification program that requires training of oil and gas waste haulers and registration of all vehicles involved in the commercial hauling of oil and gas wastes. (2010 STRONGER Guidelines, Section 4.2.5.)

Location of Closed Disposal Sites

State statute requires notice of inactive hazardous substance or waste disposal sites. DENR maintains records of all closed disposal sites for programs under its jurisdiction. Land disposal of solid wastes must be recorded on the deed.

Finding II.25.

The Review Team finds that the DENR meets Section 4.2.6. of the guidelines.

Data Management

The DLR- N.C. Geological Survey maintains copies of all permits/reports for all oil and gas wells. These records are available for public review. Staff located and provided the Review Team the records of the two wells drilled in 1998.

The DENR's Division of Water Quality also maintains a Well Construction Database for water wells. The DENR regulations require that water well drillers submit a well construction record for every well they drill. The records include information on the driller and well owner, well location, well construction characteristics, and the driller's log. Drillers submit this information on paper and DWQ staff enters the information into the database. Most of this information is subject to public disclosure upon request, but none is posted on the Internet or made available without a request.

In addition, the DWQ maintains and uses the Basin-wide Information Management System to track data on permits and compliance for the NPDES wastewater and storm water, non-discharge wastewater, UIC (Class V), and well permitting programs. Nearly all data is submitted to the DWQ on paper and entered manually into the database, with the exception of a pilot project to provide electronic submissions for some major NPDES permits. All information is public record. The DWQ makes limited permit information available on its website.

The Division of Waste Management (DWM) maintains publicly available databases related to underground storage tanks, land application sites and active and closed permitted landfills

The Division of Air Quality (DAQ) maintains publicly available databases related to air quality permits.

Finding II.26.

The DENR has no computer data management capabilities with respect to oil and gas activities.

Recommendation II.26.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR consider developing an on-line permitting and reporting data management system to efficiently track oil and gas activities. (2010 STRONGER Guidelines, Section 4.2.7.)

Personnel and Funding

The DENR has well-qualified employees dedicated to the goals and objectives of its programs. Staff includes administrative personnel, field inspectors, geologists, engineers, toxicologists, and health science specialists. As currently organized, responsibilities with respect to regulation of oil and gas activities are carried out through a coordinated review process involving program staff in multiple divisions.

The DENR has several regional offices that support headquarters. Inspectors for the various programs are assigned to areas based on the locations of the permitted facilities.

Currently there are no staff dedicated to E&P environmental regulatory program implementation; duties are distributed among existing staff in multiple divisions. A UIC grant from the EPA provides funding for one position in the DWQ. However, this position is not dedicated to E&P program implementation and North Carolina currently does not allow Class II wells.

Legal needs are filled by the DENR General Counsel and the North Carolina Attorney General's office. The State Office of Administrative Hearings provides hearing officers for appeals of permitting and enforcement decisions.

Technical personnel are capable of mapping hydrologically sensitive areas and areas containing treatable water, and provide guidance in waste handling.

Field personnel are responsible for conducting routine inspections of regulated facilities and activities to assure compliance with program requirements. In addition, field personnel are among the state agency's on-site representatives to witness critical regulated activities and to observe or supervise clean-up or remedial actions. Field personnel also are involved in the assembly of evidence for enforcement actions and in the state agency's community relations.

Finding II.27.

The review team found DENR staff directly involved in the review to be aware of and knowledgeable about issues related to shale gas development. These staff members are educating themselves on the issues, but represent a very small number of total DENR staff. The department lacks practical experience related to management of shale gas exploration and development activities.

Recommendation II.27.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR staff of the appropriate Divisions visit shale gas drilling and production sites in neighboring states to gain familiarity with E&P practices.

While DLR's Erosion & Sedimentation Control has a concerted training program, other training of DENR staff is generally performed on-the-job.

Finding II.28.

DENR does not have training competency requirements.

Recommendation II.28.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR provide for staff training regarding the regulations, policies, and criteria applicable to E&P waste management. (2010 STRONGER Guidelines, Section 4.3.1.5.)

The DENR programs currently are funded through appropriations, permit fees, and federal grants. The state statutes provide for severance taxes, which is dedicated to the implementation of the oil and gas conservation laws. However, the amount was set in 1945 and is one tenth of one cent per thousand cubic feet of natural gas. Penalties that the DENR collects are deposited in the Civil Penalty and Forfeiture Fund. Monies in the fund are distributed to the local school systems and cannot be used for operation of environmental programs.

Finding II.29.

Recent state budget issues have resulted in decreased funding for the DENR. Budget reductions have affected all of the regulatory programs with potential responsibilities for E&P activities. For example, the DLR had a decrease of 17 field staff across the division as a whole and the DWQ lost 30 positions.

Recommendation II.29.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the state provide the DENR with funding mechanisms that will provide funding adequate to create and maintain an effective E&P waste management program at a level sufficient to allow it to accomplish its environmental protection goals and objectives. Potential funding mechanisms include user fees and levies on production. The state may also want to consider dedication of fees and other revenue streams to special accounts. (2010 STRONGER Guidelines, Section 4.3.2.)

Coordination Among Agencies

The DENR has jurisdiction over oil and gas wells, impoundments, waste disposal, discharge, spill prevention and response, storm water, erosion and sediment control, and air. Radiation is regulated by the Department of Health and Human Services (DHHS). The DENR divisions coordinate their respective activities and coordinate with the DHHS Division of Health Service Regulation's Radiation Protection Section with respect to radiation issues.

Most of the regulatory programs in North Carolina are implemented under the DENR, with the exception of the Radiation Protection Section. Each division has its own administrative requirements relating to permitting, operational requirements, and financial assurance, and develops its own budget priorities. Each division has its own inspection and enforcement authorities. However, the various divisions within DENR have developed a high level of interagency coordination to avoid duplication of effort and conflicting standards for the regulated community and the public. The coordination also allows the various divisions to draw on expertise of other divisions as necessary. Where necessary, the divisions adopt memoranda of understanding. For example, the DWM and DWQ adopted a MOA in 2007 that specifies responsibilities of each division for managing contaminated sites.

In addition, the Interagency Leadership Team (ILT) is a group of agencies that coordinate to identify concerns and issues facing transportation, the environment, and the economy in North Carolina.

And, the DENR has permit coordinators who help industry determine up front what permits are necessary for a given project.

Finding II.30.

Most of the regulatory program is implemented under a single department. The Radiation Protection Section, if involved, is the only exception. The Review Team was encouraged by the good communication between all of the divisions of the DENR.

Finding II.31.

The DENR Divisions coordinate inspection activities wherever possible to avoid duplication of effort and to increase efficiencies.

Recommendation II.31.

The review team recommends that the DENR review existing agreements to ensure that they are current and effective and consider developing interagency mechanisms, such as formal meetings among the divisions, to facilitate the sharing of information among and between involved divisions with respect to E&P activities. (2010 STRONGER Guidelines, Section 4.4.)

III. TECHNICAL CRITERIA

General

North Carolina has extensive hazardous waste and solid waste management requirements but does not have specific technical criteria for E&P waste management, and does not have either a certification process for non-hazardous waste haulers or a formal waste tracking process for E&P exempt and non-hazardous solid wastes.

Currently, North Carolina law prohibits disposal of E&P wastes in solid waste landfills. Removal of that prohibition would require both legislative action and rule change. The state does not currently have siting or other technical criteria specific to E&P waste management facilities. Local zoning consistency determinations also may affect availability of future E&P waste management facilities.

The DENR has the authority to "regulate and, if necessary in its judgment for the protection of unique environmental values, to prohibit the location of wells in the interest of protecting the quality of the water, air, or any other environmental resource against injury, or damage, or impairment."

Setbacks and water table separation requirements in 15A NCAC 2T for land application of wastewater or wastewater treatment residuals may apply to land-spreading of E&P wastes. State rules also include setbacks and rock/water table separation requirements for landfills.

Various existing riparian and water table siting requirements may apply to E&P wastewater management or disposal facilities. Oil and gas drilling and completion regulation 15A NCAC 05D.0107 uses the term "fresh water" with respect to surface casing requirements, but the term is not defined in law or regulation for any purpose. North Carolina considers all groundwater to be "fresh water," but has two different groundwater classifications based on the salinity of the groundwater.

Finding III.1.

North Carolina does not have technical criteria specific to E&P waste management.

Recommendation III.1.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR develop and adopt E&P waste management standards and design specifications based on site-specific geology, hydrology, climate, and waste characteristics consistent with the Guidelines. (2010 STRONGER Guidelines, Section 5.1.)

Finding III.2.

North Carolina does not have a certification or formal waste tracking process for non-hazardous waste haulers, or siting or other technical criteria specific to E&P waste management facilities.

Recommendation III.2.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR develop and adopt E&P waste hauler certification and E&P waste tracking programs consistent with the Guidelines. (2010 STRONGER Guidelines, Section 5.1.) Existing land-farming facilities are most likely to initially receive E&P exempt wastes. The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR develop management and siting criteria specific to E&P activities prior to drilling permit issuance and initial waste generation. (2010 STRONGER Guidelines, Section 5.1.)

Finding III.3.

There are limited siting criteria concerning Deep River Basin sensitive areas, surface waters, and depth and quality of groundwater.

Recommendation III.3.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the state evaluate current requirements based on characterization of anticipated E&P wastes and operations, communicate guidance to operators for drilling and production program planning, and provide public notice of such siting requirements. The state should define "fresh water" for purposes of the Oil and Gas Act and ensure that the definition is consistent with the state's water quality classifications and standards. Groundwater with a naturally occurring concentration of chloride greater than 250 mg/l is GSA, or groundwater "for potable mineral water and conversion in fresh waters." Groundwater with less than 250 mg/l of naturally occurring chloride is class GA, fresh water intended for use as drinking water. State water quality standards include standards for chloride and for total dissolved solids (TDS) that are applicable to each classification. (2010 STRONGER Guidelines, Section 5.1.)

Waste Characterization

The DENR implements general solid waste management standards and definitions consistent with federal regulations, but focused on RCRA hazardous waste treatment, storage, and disposal. The DWQ regulations specify requirements for chemical, physical, or biological analyses to determine conformity with surface water quality standards (15 NCAC 2B.0103) and wastewater quality for land-applied wastewater. There are currently no authorized commercial E&P waste management facilities, although current land-farming disposal sites may accept non-hazardous E&P wastes. Federal hazardous waste determination, treatment, disposal, and analytical requirements under 40 CFR 262 are adopted by reference.

Finding III.4.

North Carolina has not developed regulations specific to treatment, storage, and disposal facilities for E&P waste.

Recommendation III.4.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the appropriate rulemaking bodies should establish regulations specific to treatment, storage, and disposal facilities for RCRA-exempt and non-hazardous E&P wastes, including drilling fluids, cuttings and produced water. (2010 STRONGER Guidelines, Section 5.2.1.)

Finding III.5.

The DENR implements solid waste management characterization requirements consistent with federal regulations, surface water analytical requirements, and land-application criteria.

Recommendation III.5

Because existing waste characterization requirements focus on RCRA hazardous wastes and municipal solid waste, if North Carolina decides to develop an oil and gas regulatory program, the review team recommends that the state develop E&P exempt and non-hazardous solid waste characterization protocols, including for NORM. (2010 STRONGER Guidelines, Section 5.2.2.)

Finding III.6.

The state has adopted general solid waste management quality control provisions consistent with federal regulations.

Recommendation III.6.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR evaluate quality control requirements to ensure that they meet needs unique to E&P waste testing. (2010 STRONGER Guidelines, Section 5.2.3.)

Waste Management Hierarchy

The North Carolina General Statutes spell out a standard waste management hierarchy as the preferred method of waste management in the state, with source reduction first, followed by recycling and reuse, composting, incineration with energy recovery, incineration without energy recovery, and landfilling. However, there are no state statutes or policies that specifically promote source reduction and recycling for the oil and gas industry. The Division of Environmental Assistance and Outreach develops and maintains programs that provide technical assistance on the reduction and recycling of wastes and emissions, but has had little experience with oil and natural gas operations and resulting waste streams. Some generic waste streams possibly generated by oil and gas operations (e.g., waste oil, oil filters, and wooden pallets) are banned from solid waste disposal in North Carolina.

Finding III.7.

North Carolina statutes integrate the waste management hierarchy into other elements of the DENR programs for management of wastes.

Recommendation III.7.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR integrate the waste management hierarchy into any oil and gas programs consistent with 5.3. of the Guidelines.

Technical Criteria for Pits

Under North Carolina law, drilling of an oil or gas well cannot start until any associated pits have been installed to the satisfaction of the regulatory agency. The state has not developed any specific pit program requirements; the regulatory agencies determine requirements on a case-by-case basis.

Finding III.8.

The review team found that the state has no specific technical requirements in place for pits.

Recommendation III.8.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR develop a specific regulatory program that includes technical requirements for pits associated with E&P activities that meet the criteria of sections 5.51-5.55 of the Guidelines when oil and gas development begins. (2010 STRONGER Guidelines, Section 5.5.)

<u>LANDSPREADING</u> <u>(Non-Commercial)</u>

The DENR regulates land-spreading as soil remediation under 15A NCAC 2T.1500 or as a residual under 15A NCAC 2T.110. Approvals are required for each land-spreading event.

Finding III.9.

The review team found that there are no naturally occurring radioactive materials (NORM) action levels for land-spreading of E&P waste.

Recommendation III.9.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program and determines that oil and gas NORM waste is an issue, the state develop NORM action levels for land-spreading. (2010 STRONGER Guidelines, Section 5.6.1.c.)

Finding III.10.

The review team found that there are no specific land-spreading practices defined for E&P sites that address the operational requirements of section 5.6.3 of the guidelines.

Recommendation III.10.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR develop a more comprehensive land-spreading policy that meets the guidelines. (2010 STRONGER Guidelines, Section 5.6.)

Technical Criteria for Burial and Landfilling

The DENR permits solid waste landfills. However, current state law and DENR regulations prohibit the disposal of petroleum wastes in landfills. Road-spreading of E&P wastewaters would be subject to design criteria, use requirements, and requirements for operational plans for reclaimed water systems.

Finding III.11.

The state has no technical criteria for burial, landfill, or road-spreading specific to E&P wastes. State requirements and laws prohibit landfills from accepting any petroleum or E&P waste.

Recommendation III.11.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the state should develop and adopt technical requirements for burial, landfilling, and road-spreading specific to E&P wastes consistent with the 2010 STRONGER Guidelines. (2010 STRONGER Guidelines, Section 5.7.)

Technical Criteria for Tanks

The DENR would regulate the location and size of tanks at E&P sites through conditions in the master drilling permit. General tank requirements are determined as part of the master drilling permit application, on a case-by-case basis by the DLR in coordination with the DWM and DWQ. Related impoundment and other containment facility hazardous waste permit requirements are contained in 40 CFR 270.14, which has been adopted by reference, but there are currently no long-term hazardous waste disposal facilities in the state.

Finding III.12.

The state does not currently have E&P-specific tank requirements.

Recommendation III.12.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the state should adopt siting, safety, environmental, reporting and administrative requirements for operational oil and produced water tanks and for RCRA Subtitle C exempt E&P waste management consistent with the Guidelines. (2010 STRONGER Guidelines, Section 5.9.)

Finding III.13.

North Carolina does not have standards for spill prevention, preventive maintenance or inspections for tanks used for E&P.

Recommendation III.13.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR adopt E&P-specific oil and produced water tank spill prevention, preventive maintenance, and inspection best practice guidance or standards consistent with the Guidelines. (2010 STRONGER Guidelines, Section 5.9.)

Finding III.14.

The state does not have E&P-related tank construction and operating standards. Such standards are determined on a case-by-case basis by the DLR in coordination with the DWM and the DWQ.

Recommendation III.14.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR adopt E&P tank construction and operating standards, including measures for secondary containment and control of hydrogen sulfide (if appropriate) consistent with the Guidelines. (2010 STRONGER Guidelines, Section 5.9.)

Finding III.15.

The state program does not have E&P-related tank removal and closure requirements. E&P tank standards will be determined on a case-by-case basis by the DLR in coordination with the DWM and the DWQ.

Recommendation III.15.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR adopt E&P tank removal and site closure standards consistent with the Guidelines. (2010 STRONGER Guidelines, Section 5.9.)

IV. ABANDONED SITES

Between 1925 and 1997, 126 oil and gas wells were drilled in North Carolina, but none of the wells produced commercial quantities of oil and gas and they were plugged according to the standards of the day. In 1998, two exploratory wells were drilled in central North Carolina, but are not in production and remain under permit and bond.

The Oil and Gas Conservation Act requires that all wells be sealed completely from the bottom to the top. The DENR maintains records, locations and other miscellaneous well data for all wells completed.

The state also currently has funding mechanisms for plugging abandoned wells as bonding requirements are currently in place. The state requires a bond in the amount of $5,000 plus $1 per linear foot for any proposed wells to be drilled. The bonds cover only the proper plugging of the well. The last two wells drilled in 1998 still have open bonds to cover any damage.

The Oil & Gas Conservation Act (G.S. 113 Article 27) defines certain E&P terms, such as "oil and gas developer or operator," "developer or operator," "oil and gas operations," or "activities". However, neither the statutes nor the regulations include any definitions pertaining to abandoned sites.

North Carolina public records law requires agencies to maintain state records and make nearly all of those records available to the public. There are limited exceptions for trade secrets. Oil and gas files are maintained by the North Carolina Geological Survey and are filed by location in file cabinets at the North Carolina Geologic Survey Field Office and Core Repository.

When abandoning a well, a log of the drilling and development of each well is required by G.S. 113-379. G.S. 113-391 requires a reasonable bond condition for the performance of the duty to plug each dry or abandoned well. G.S. 113-395, as amended by S.L. 2011-276, requires notice that the well is to be abandoned and requires a $450 fee.

Finding IV.1.

The review team commends the DENR for its recordkeeping and file maintenance.

Finding IV.2.

The review team commends the DENR staff for its openness and transparency with regards to sharing records and for its strong collaborative effort.

Finding IV.3.

The review team found that the State of North Carolina currently has no abandoned oil and gas sites in the state.

Recommendation IV.3.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR consider defining terms associated with abandoned E&P sites. The review team further recommends that the state consider developing a process for prioritizing and ranking both the 126 existing plugged wells and wells permitted in the future based on potential risk. In addition, the state may want to consider cutting well casings to 3 ft. below plow depth in areas of agricultural use. (2010 STRONGER Guidelines, Section 6.3. and Section 6.5.)

V. NATURALLY OCCURING RADIOACTIVE MATERIAL

With little or no drilling activity in North Carolina in recent years, oilfield NORM has not been an issue at the DENR.

However, in 2011 the North Carolina General Assembly passed Session Law 2011-276 (House Bill 242), which directs the DENR to study the issue of oil and gas exploration in the state, specifically the use of horizontal drilling and hydraulic fracturing, and report back to the legislature by May 1, 2012. Part of that study will include testing for NORM.

Earlier this year, the Geologic Survey Division of the DLR conducted initial surveys of shale outcrops in the Sanford and Dan River basins and reports finding radioactivity levels 2.5 times the background levels, but well below levels of concern for public health. The DLR also has collected additional samples (164 from Sanford and 165 from Dan River) for further testing.

The Radiation Protection Section of the Division of Health Services Regulation in the Department of Health and Human Services regulates radiation in North Carolina (Radiation Protection Act: G.S. 104E), but does not regulate NORM unless the radioactivity exceeds an action level. The action level differs for each radioactive element.

North Carolina radiation protection rules at 15A NCAC 11 state that, if NORM is concentrated by natural means above the action level, shielding to protect persons from accidentally exposing themselves would be required. In addition, if NORM is concentrated by mechanical or chemical means above the action level (technologically enhanced), that process of concentration would require a permit from RPS. These technologically enhanced materials would be considered by-product materials.

While the state does have storage facilities for radioactive waste materials, they do not have disposal facilities for this material. All such waste is shipped out of state.

Finding V.1.

The DLR is conducting a study to determine the extent and potential impacts of oil field NORM.

Recommendation V.1.

If North Carolina decides to develop an oil and gas regulatory program, and if the state determines that NORM is an issue in E&P activities, the review team recommends that the state develop an E&P regulatory program consistent with Section 7 of the Guidelines.

VI. STORMWATER MANAGEMENT

General

The state's Sedimentation Pollution Control Act of 1973 governs all land-disturbing activities except those associated with agriculture and mining. Mining activities are regulated under the Mining Act of 1971. Erosion and sedimentation control are required regardless of the size of the area disturbed. The law requires the landowner to plan and implement effective temporary and permanent control measures to prevent accelerated erosion and off-site sedimentation. The DLR erosion and sediment control program maintains extensive web-based material available for industry and public stakeholder education and outreach.

The state maintains primacy for all federal storm water programs, but does not have E&P-specific stormwater permitting requirements. In addition to construction stormwater requirements (largely implemented through the state sedimentation program), E&P activities may also be subject to post-construction stormwater control requirements in some areas of the state. Post-construction stormwater requirements do not apply statewide and are implemented through a number of different programs – both federally delegated (such as the Phase II stormwater program) and "state only" programs. The "state only" post-construction stormwater permitting programs typically apply to new development activity within certain sensitive areas or in areas draining to impaired waters. Examples would be nutrient sensitive river basins and water supply watersheds. These programs are implemented by the DWQ or by local governments with oversight by the DWQ. Since post-construction stormwater requirements do not apply statewide, E&P activities in many areas of the state would not require stormwater controls after completion of initial construction. Pollutants in stormwater leaving the site after construction would not be regulated until a water quality impact actually occurred.

The state also has the authority to issue Water Quality Certifications under Section 401 of the federal Clean Water Act; under Section 401, an applicant seeking a Federal Section 404 Permit to discharge to navigable waters)which includes certain wetlands connected to those waters) must provide a certification that the discharge will meet state water quality standards. A State Isolated Wetlands and Waters Permit is required to impact isolated wetlands or waters that fall outside federal jurisdiction under Section 404.

Finding VI.1.

The combination of the DWQ state stormwater and DLR erosion/ sediment control programs are adequate to meet the General criteria of the Guidelines.

Recommendation VI.1.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR develop an operator and public on-line resource identifying the E&P stormwater permit requirements and the best management practices for the E&S program. (2010 STRONGER Guidelines, Section 8.1.)

State Regulatory Program Elements

The state does not have E&P specific regulatory or best practice stormwater minimization requirements, but the extensive DLR Erosion and Sediment Control program, pursuant to 15A NCAC Ch. 4, appears to be an industry standard for sediment and erosion control. The E&S program includes regular training, guidance on inspection, auditing, and reporting, and community outreach.

State stormwater programs that address post-construction stormwater do not have E&P-specific regulatory standards or best management practice stormwater minimization requirements. In areas where the existing state stormwater programs apply, the programs establish best management practices (BMPs) and methods for minimizing environmental impacts from stormwater pollution. The programs also provide training, guidance on inspections, auditing, reporting and community outreach.

Finding VI.2.

The state partially meets Section 8.2 of the Guidelines related to state stormwater management regulatory program elements.

Recommendation VI.2.
The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR review and consider incorporating the appropriate elements of the comprehensive E&S program to meet the Guidelines (see note below). (2010 STRONGER Guidelines, Section 8.2.)

Agency Regulatory Program Criteria

All surface waters in North Carolina are classified as to best use. In areas where the use is threatened because of impaired water quality or maintenance of an existing use (such as water supply) measures to address nonpoint source pollution are required. There are restrictions on development in the contributing watersheds and/or restrictions as to permissible storm water or wastewater pollutant discharges. Discharges may be restricted based on classifications: Outstanding Resource Waters, High Quality Waters, Trout Waters, Water Supply I – V, Critical Area, Shell-fishing Waters, Nutrient Sensitive Waters, and zero-flow streams.

The state does not have E&P-specific standards or best stormwater management minimization requirements, but the state's existing programs cover many of the activities associated with E&P. The state's Stormwater BMP Manual and rules address many of the stormwater control measures identified in the Guidelines. In areas of the state where no state stormwwater standards apply, only sediment pollutants and stormwater impacts associated with later phases of E&P activity would be addressed in existing rules.

Finding VI.3

There are gaps in the state's regulation of stormwater pollution outside the initial land-clearing and construction phase. In many areas of the state, stormwater generated during well drilling and production would not be addressed by the state's existing programs and only sedimentation impacts would be regulated during the construction phase.

Recommendation VI.3.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DLR and DWQ should work together to develop standards to address gaps in the state's existing stormwater program to ensure that stormwater from all phases of E&P and all potential pollutants from E&P are addressed in accordance with the Guidelines. (2010 STRONGER Guidelines, Section 8.3.2.)

Finding VI.4.

The DENR E&S control design manual and other resources are extensive, and address planning, construction standards, operation, maintenance, restoration, and reclamation criteria related to erosion and sedimentation control. The manual does not contain E&P-specific standards and does not address pollutants other than sediment.

Recommendation VI.4.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DLR combine E&P-related best management practices from the design manual into an oil and gas guidance document to facilitate use by the industry. (2010 STONGER Guidance, Section 8.3.)

VII. HYDRAULIC FRACTURING

Currently, shale gas development in most areas of the country relies heavily on the use of horizontal well drilling and hydraulic fracturing technologies.

Rule 15A NCAC 05D.0107(e) states "All wells shall be drilled in such a manner so that vertical deviation of the hole does not exceed three degrees between the bottom of the hole and the top of hole, and shall not deviate in such a manner as to cross property or unit lines, unless an exception is granted by the director. An inclination survey shall be filed with the director for each well subsequently produced for oil or gas." The DENR has interpreted this regulation to prohibit the drilling of horizontal oil and gas wells.

Rule 15 NCAC 02C.0213(e)(1), relating to the operation of Class V injection wells, requires that "Pressure at the well head shall be limited to a maximum which will ensure that the pressure in the injection zone does not initiate new fractures or propagate existing fractures in the injection zone, initiate fractures in the confining zone, or cause the migration of injected or formation fluids outside the injection zone or area." The DENR has interpreted this to prohibit hydraulic fracturing of oil and gas wells.

Finding VII.1.

The DENR currently believes that horizontal drilling and hydraulic fracturing are prohibited under North Carolina regulations.

Recommendation VII.1.

The review team recommends that, if North Carolina decides to develop an oil and gas regulatory program, the DENR obtain legal opinions from the Attorney General regarding the interpretation of Rule 15A NCAC 05D.0107(e) and Rule 15 NCAC 02C.0213(e)(1). If the Attorney General's opinions concur with the current DENR interpretations, the DENR should develop regulations for horizontal drilling and hydraulic fracturing that meet the criteria contained in Section 9 of the Guidelines. (2010 STRONGER Guidelines, Section 9.)

APPENDIX A

Acronyms

AAL	Accepted Ambient Levels
APA	Administrative Procedures Act
CFR	Code of Federal Regulations
DAQ	Division of Air Quality
DENR	Department of Environment and Natural Resources
DHHS	Department of Health and Human Services
DLR	Division of Land Resources
DPS	Department of Public Safety
DWM	Division of Waste Management
DWR	Division of Water Resources
DWQ	Division of Water Quality
E&P	Exploration and Production
EMP	Emergency Management Plan
EOC	Emergency Operations Center
FEMA	Federal Emergency Management Agency
HAZMAT	Hazardous Materials
ILT	Interagency Leadership Team
IOCC	Interstate Oil Compact Commission
IOGCC	Interstate Oil and Gas Compact Commission
LEPC	Local Emergency Planning Committee
NORM	Naturally Occurring Radioactive Materials

MOU	Memorandum of Understanding
RCRA	Resource Conservation and Recovery Act
RPS	Radiation Protection Section
RRC	Rules Review Commission
SAB	Science Advisory Board
SEOP	State Emergency Operations Plan
SPCC	Spill Prevention, Control and Countermeasures
STRONGER	State Review of Oil and Natural Gas Environmental Regulations, Inc.

APPENDIX B

INFORMATION FOR THE REVIEW OF STATE OIL AND GAS ENVIRONMENTAL REGULATORY PROGRAMS IN STATES WITH A SMALL NUMBER OF WELLS

State: North Carolina

Completed by NC Department of Environment and Natural Resources

Address 1601 Mail Service Center
Raleigh, NC 27699-1601

Telephone (919) 715-2613 Fax (919) 715-3060

Questionnaire Coordinator/Contact: Trina Ozer

INSTRUCTIONS: The primary basis for this review is the document, Guidelines for State Review of Oil and Natural Gas Environmental Regulatory Programs (2010). Please provide the information requested herein and be prepared to describe and discuss the additional information as requested. However, avoid providing background information, data, regulations or statutes that do not address issues in the Guidelines or are not related to the state's oil and gas environmental programs. (For example, regulation of underground fuel storage tanks is not addressed in this review.) Terms used in this questionnaire have meanings consistent with those contained in the Guidelines. Citations appearing in brackets (e.g., [5.3.]) refer to the applicable section or sections of the Guidelines.

REQUESTED BACKGROUND INFORMATION

1. Please provide a brief history or other description of the oil and gas industry in your state, its regulation by state agencies, and recent E&P trends.

Though natural gas and oil are known to occur in North Carolina, they are not currently produced in the state. Natural gas and oil can potentially be produced in commercial quantities from two general geologic regions: 1) the Mesozoic basins that are exposed in the Piedmont or lie buried beneath the Atlantic Coastal Plan, and 2) the Atlantic Outer Continental Shelf.

The history of oil and gas exploration in North Carolina spans over 80 years, with the earliest oil well drilled in 1925 in Craven County. Oil and gas exploration wells have been drilled in 23 counties across the state. The most active exploration years, those with ten or more wells completed, were: 1971 with 19, 1969 with 13, 1958 with 11, and 1966 with 10. To date, 127 oil and gas exploration wells have been completed in North Carolina. Since 1974, seven wells have been drilled, all in Lee County. The most recent oil and gas wells were drilled in 1998 in Lee County.

People interested in drilling an exploratory well for oil or gas are required to register with DENR, post a bond, and submit an application for a drilling permit to the Division of Land Resources (DLR). The bond is $5,000 plus $1 per linear foot proposed to be drilled. A permit is also required for all geophysical exploration work, including seismic explorations. Explorations are defined as geological, geophysical and other surveys and investigations, including seismic methods for the discovery and location of oil, gas or other mineral prospects, and which may or may not involve the use of explosives.

Recently, companies have approached landowners in Chatham, Lee and Moore Counties about leasing their mineral rights, and many of these landowners have signed lease agreements.

2. Please also include a copy of the following:

   A. Organization chart(s) showing the structure of all agencies responsible for the management and disposal of exploration and production (E&P) wastes, abandoned oil and gas sites, oil-field NORM (naturally occurring radioactive materials), storm water management and hydraulic fracturing.

There is an org chart for DENR attached. The units involved in the management of E&P wastes are the Division of Waste Management, the Division of Water Quality, the Division of Water Resources, the Division of Land Resources, and the Division of Air Quality. In addition to DENR divisions, the Radiation Protection Section (RPS) of the Division of Public Health in the Department of Health and Human Services would be involved. Org charts for each of these divisions are also attached.

B. Statutes, rules, regulations and orders applicable to the management and disposal of oil and gas E&P waste, abandoned oil and gas sites, NORM from oil and gas production, storm water management and hydraulic fracturing.

C. Any memoranda of understanding or similar agreements between state agencies or between the state and any other governmental entities (BLM, EPA, Indian Tribes, local jurisdictions) pertaining to the management and disposal of E&P wastes, abandoned sites, NORM from oil and gas production, storm water management and hydraulic fracturing.

UIC: The 1984 Memorandum of Agreement between EPA and North Carolina for the UIC Program is attached. The state applied for renewal of its UIC primacy in 2002, but EPA is still reviewing the application. The 2002 Memorandum of Agreement is also attached, but has not been signed by EPA.

NPDES: The 2007 Memorandum of Agreement between EPA and North Carolina for the NPDES Program is attached. This MOA covers the NPDES wastewater, NPDES stormwater, and pretreatment programs.

D. Any written mission statement(s), goals, objectives and policies applicable to oil and gas E&P waste management and disposal activities, abandoned sites, NORM from oil and gas production, storm water management and hydraulic fracturing.

The DENR 2009-2013 Strategic Plan states DENR's mission and values (see introduction) and also states that DENR should "continue and support the evaluation and exploration of natural gas resources in the state" (p. 5). Other sections have broader relevance. For instance, the Plan includes actions such as: "Improve the state's response to groundwater contamination incidents through improved coordination among state agencies and local governments, stronger enforcement policies and increased public education" (p. 2) and "Partner with business, the Department of Transportation and the Department of Commerce to effectively reduce diesel emissions from the movement of freight and limit diesel emissions from construction activities" (p. 4).

3. Also, please include on a separate page any other relevant practices, program measures, guidelines or controls applicable to your state.

Session Law 2011-276 directs DENR to study the issue of oil and gas exploration in the state, specifically the use of directional and horizontal drilling (see http://www.ncleg.net/Sessions/2011/Bills/House/PDF/H242v7.pdf).

4. The next pages contain a matrix to be used to summarize E&P waste management practices. It is recognized that further explanation will likely be necessary. Don't try to capture everything or give precise numbers if not readily available - give only the big picture in the matrix.

E&P Waste Management Matrix

Waste Management Practices	**Number of Facilities**	**Volume Managed Annually**	**Basis for Volume Determination**
Pits:			
Drilling	**0**		
Production	**0**		
Special Use	**0**		
Landspreading	**0**		
Roadspreading	**0**		
Tanks	**0**		
Commercial Facilities:			
Multipractice	**0**		
Landfarms	**0**		
Tank Bottom Reclaimers	**0**		
UIC Surface Facilities	**0 (Class II)**		
Oil-Field NORM	**0**		
Centralized Facilities (non-NORM)	**0**		
Oil-Field NORM	**0**		
Municipal Landfills Accepting E&P Waste	**0**		
Underground Injection Surface Facilities	**0 (Class II)**		
Abandoned Sites	**0**		
Other	**0**		

E&P Waste Management Matrix (cont.)

Waste Management Practice	Principal Agency	Primary Statute	Primary Rules, Regulations, or Orders	Applicable Guidelines
Pits:				
Drilling	DLR	Chapter 113, Article 27 (see attached document)	15A NCAC .05D	
Production	DLR	Same as above		
Special Use	DLR	Same as above		
Landspreading	DWQ	G.S. 143-215.1	15A NCAC 2T	
Roadspreading	DWQ	G.S. 143-215.1	15A NCAC 2U	N/A
Tanks (produced water, production tanks)	Depends on contents – DLR, DWM		DWQ – none, DWM: 15A NCAC 13A .0113	
Commercial Facilities: (facilities used by multiple operators)				
Multipractice	DWM			
Landfarms	DWQ or DWM depending on specifics	G.S. 143-215.1	15A NCAC 13B 15A NCAC 2T	
Tank Bottom Reclaimers	DWM			
UIC Surface Facilities	DWQ	G.S. 143-214.2(b)	15A NCAC 2C .0209(b)	N/A
Oil-Field NORM	DHHS-RPS	G.S. 104E	15A NCAC 11	
Centralized Facilities (non-NORM)	DLR or DWM			
Oil-Field NORM	DLR, DHHS-RPS	G.S. 104E	15A NCAC 11	
Municipal Landfills Accepting E&P Waste	DWM - would have to be legislative and/or rule making			

	enacted. Landfills do not currently accept petroleum wastes.			
Underground Injection Surface Facilities	DWQ	G.S. 143-214.2(b)	15A NCAC 2C .0209(b)	N/A
Abandoned Sites	DLR	G.S. 113, Article 27		
Other	TBD			
Wastewater Pump & Haul Permits	DWQ	G.S. 143-215.1	15A NCAC 2T .0200	N/A
Other non-discharge wastewater systems	DWQ	G.S. 143-215.1	15A NCAC 2T	N/A

During the in-state review, please be prepared to describe and discuss the following if they are applicable in your state:

I. GENERAL CRITERIA

1. The **statutory authority** upon which your E&P environmental regulatory program is based. [3.1.a]
   - Well Construction Act: G.S. 87, Article 7 (well construction standards, injection wells)
   - Oil & Gas Conservation Act: G.S. 113, Article 27 (issues related to exploration and production)
   - Water and Air Resources Act: G.S. 143, Article 21 (issues related to protection of air and water resources; wastewater and stormwater management)
   - Air Pollution Control: G.S. 143, Article 21B
   - Oil Pollution and Hazardous Substances Control: G.S. 143, Article 21A
   - Oil Spill Contingency Plan: G.S. 166A
   - Solid Waste: G.S. 130A, Article 9
   - Radiation Protection Act: G.S. 104E

2. Authority for the **promulgation of rules and regulations.** [3.1.b]
   - G.S. 87-87 (EMC authority to adopt well construction rules)
   - G.S. 113-391(c) (Department authority to adopt rules under Oil & Gas Conservation Act)
   - G.S. 143-215.3(a)(1) (EMC authority to promulgate rules under G.S. 143 Articles 21 – water and air resources, 21A – oil pollution and hazardous substances control, 21B – air pollution control and 38 – water resources)
   - G.S. 143B-282 (Creation of EMC)
   - Solid Waste G.S. 130A-29
   - Oil Spill Contingency Plan: G.S. 166A
   - Radiation Protection G.S. 104E-7

3. The **definitions** of terms necessary for program implementation. [3.1.c]

See above. Terms are defined within each statute and administrative code

4. The adequacy of **levels of funding and staff** provided for E&P environmental regulatory program implementation (differentiate between UIC and non-UIC program funding and staffing levels if applicable to your program). [3.1.d, 4.3.2]

Currently there are no staff dedicated to E&P environmental regulatory program implementation; duties are distributed among existing staff in multiple divisions. A UIC grant from EPA provides funding for one position in DWQ. However, this position is not dedicated to E&P program implementation and North Carolina currently does not allow Class II wells.

5. Mechanisms for the **coordination** of E&P environmental regulatory program activities among the public, government agencies and the regulated industry. [3.1.e, 4.4]

Most of regulatory program is implemented under a single department (Radiation Protection, if involved, the only exception). A 2007 MOA between DWM & DWQ (attached) specifies the responsibilities of each division for managing contaminated sites. North Carolina has primacy for the UIC program for all classes of injection wells.

6. The **goals or objectives** of the E&P environmental regulatory program (including how the goals and objectives relate to protection of human health and the environment). [3.2]

The Water & Air Resources Act, in G.S. 143-211, establishes the broadest goals and objectives for the state's environmental protection programs:

143‑211. Declaration of public policy.

(a) It is hereby declared to be the public policy of this State to provide for the conservation of its water and air resources. Furthermore, it is the intent of the General Assembly, within the context of this Article and Articles 21A and 21B of this Chapter, to achieve and to maintain for the citizens of the State a total environment of superior quality. Recognizing that the water and air resources of the State belong to the people, the General Assembly affirms the State's ultimate responsibility for the preservation and development of these resources in the best interest of all its citizens and declares the prudent utilization of these resources to be essential to the general welfare.

(b) It is the public policy of the State to maintain, protect, and enhance water quality within North Carolina....

(c) …It is the intent of the General Assembly, through the duties and powers defined herein, to confer such authority upon the Department of Environment and Natural Resources as shall be necessary to administer a complete program of water and air conservation, pollution abatement and control and to achieve a coordinated effort of pollution abatement and control with other jurisdictions. Standards of water and air purity shall be designed to protect human health, to prevent injury to plant and animal life, to prevent damage to public and private property, to insure the continued enjoyment of the natural attractions of the State, to encourage the expansion of employment opportunities, to provide a permanent foundation for healthy industrial development and to secure for the people of North Carolina, now and in the future, the beneficial uses of these great natural resources. It is the intent of the General Assembly that the powers and duties of the Environmental Management Commission and the Department of Environment and Natural Resources be construed so as to enable the Department and the Commission to qualify to administer federally mandated programs of environmental management and to qualify to accept and administer funds from the federal government for such programs.

The Well Construction Act of 1967 (G.S. 87, Article 7) establishes "the policy of this State to require that the location, construction, repair, and abandonment of wells, and the installation of pumps and pumping equipment conform to such reasonable requirements as may be necessary to protect the public welfare, safety, health and groundwater resources."

- Oil & Gas Conservation Act: G.S. 113-382 and as amended by S.L. 2011-276
- See list of statutory authorities in the table above.

7. Any **flexibility** in determining the criteria applicable to E&P environmental activities (e.g., variation in criteria dependent on region of the state or other factors). [3.3]

- Customized permit conditions (DLR)
- Most regulatory programs administered by NC DENR include provisions for the issuance of variances when compliance with standards is not technically feasible or when a greater level of protection can be provided through alternatives that do not otherwise comply with standards. Statutory variance authorities include:
  - G.S. 143-215.3(e), for variances from standards established by the EMC under G.S. 143-215.1 (Control of sources of water pollution).
- In addition to these statutory authorities, variance authority is found in the following administrative code rules:
  - 15A NCAC 2B .0226 (Variance from surface water standards)
  - 15A NCAC 2C .0118 (Variances from well construction standards)
  - 15A NCAC 2C .0215 (Variances from injection well rules)
  - 15A NCAC 2L .0113 (Variances from groundwater standards)
  - 15A NCAC 2T .0105(b) (Variances from design criteria for non-discharge wastewater)

II. ADMINISTRATIVE CRITERIA

1. Mechanisms for **approval of permits, registration, notification**) to assure that E&P environmental impacts are managed responsibly. [4.1.1]

For oil and gas permits the applicant must register, provide a bond, and then apply for the permit. For other waste management and wastewater issues, existing processes for industrial facilities would be used.

An application for a drilling permit for an oil or gas well triggers a series of other permits which must be obtained prior to the issuance of a drilling permit. The applicant submits a site plan, which entails describing where the drilling is proposed, how deep the drilling is planned, the casing specification for the well, and the plan for on-site storage of water, wastewater and mud in pits and/or tanks.

As soon as the Division of Land Resources receives the drilling permit application, that information is shared with other NC DENR divisions to determine what other issues must be addressed. The drilling permit is the master permit and as such, the applicant must obtain a well construction permit before receiving a drilling permit. In addition, a sedimentation and erosion control permit is also required if more than one acre of land is disturbed (this includes the access road to the site). The S&EC permit requires a site plan and a site restoration plan after the disturbance is completed.

Conditions are placed on the drilling permit that address site location, endangered or threatened wildlife species, off-site runoff, waste management, inspections and notification.

2. The **authority to refuse** to issue or reissue permits or authorizations. [4.1.1]

DLR issues a drilling permit when all conditions and requirements of the permit have been addressed to the satisfaction of the permitting authority. Under G.S. 113-402, "a party who is dissatisfied with a decision or order of the Department under this Article may obtain administrative review of the decision by filing a petition for a contested case hearing under G.S. 150B-23 within 10 days of the decision or order is made. Other facilities (well construction, solid waste, wastewater, etc) do have authority in statutes above.

3. Any notice of the permittee's obligation to comply with other federal, state or local requirements. [4.1.1]

The permit conditions of the master drilling permit require the applicant to comply with existing law. G.S. 113-408 allows the Department to bring suit in Superior Court to restrain people from continuing violations or from carrying out the threat of violations. The requirements of DLR's permit are listed in the Well Construction rules at 15A NCAC 2C .0100.

4. Fixed terms and renewal procedures for individual permits. [4.1.1]

Drilling permits are for a single use. Once bonded, a site should be drilled because the erosion and sedimentation control permit and other permits expire. Other waste facilities have a five-year permit cycle, except for a few programs which allow up eight years.

5. Your **compliance evaluation program** for:
    a. Receipt, evaluation, retention, and investigation of required notices and reports. [4.1.2.1]
    b. Inspection, sampling and surveillance procedures for facility monitoring, periodic inspections, comprehensive surveys, and violation investigation. [4.1.2.1.b]
    c. Public complaint and follow-up, including response times. [4.1.2.1.c]
    d. Authority to conduct unannounced inspections and investigations. [4.1.2.1.d]
    e. Right of entry for inspection and copying of records. [4.1.2.1.e]
    f. Chain of custody/evidence gathering. [4.1.2.1.f]

Oil & Gas Conservation:

- G.S. 113-391 describes DENR's authority to make appropriate inquiries to determine whether or not waste (as defined at G.S. 113-389) exists or is imminent.

Solid Waste:

- Statutory authorities: G.S. 130A-294
- Right of entry: G.S. 130A-17

Water Quality and Air Quality:

- G.S. 143-215.3(a)(2) - authority for DWQ to carry out investigations and inspections, enter property, examine records and collect evidence related to determining the condition of the air and water resources of the state and the condition of any pollution control equipment.

Well Construction

- G.S. 87-90 – authority for DWQ to carry out investigations and inspections, enter property, examine records and collect evidence related to determining compliance with the Well Construction Act

6. The **enforcement actions** can be taken for violations of E&P environmental regulatory requirements, including the number of times these enforcement actions have been taken by the state over the past two years (number or frequency), or an indication which of these actions the state uses more often. [4.1.3.1]

Oil & Gas Conservation:

- Level of activity is N/A.
- G.S. 113-408 gives DENR authority to obtain injunctions when it appears the statute is being violated.
- G.S. 113-409 makes evading any rule under Article 27 or falsifying information a Class 2 misdemeanor.
- G.S. 113-410 describes penalties for violations.
- G.S. 113-411 discusses illegal oil and gas.

Solid Waste:

- Determining penalties for violations of the Solid Waste Management Act: 15A NCAC 13B.0702 - .0706.
- Guidelines for transporting, collecting or recycling used oil (violation is a misdemeanor): G.S. 130A-309.17.

Well Construction:

- G.S. 87-94 and 87-95 provide authority for civil penalties and injunctive relief, respectively, for violations of the Well Construction Act.

Water & Air Quality:

- G.S. 143-215.6A, G.S. 143-215.6B, and G.S. 143-215.6C provide enforcement authority in the form of civil penalties, criminal penalties, and injunctive relief for violations under the Water & Air Resources Act.

7. Any **formula for calculation of penalties**, its regulatory basis, and the penalties assessed and collected over the past two years. [4.1.3.2]

Maximum fines are set in statute for wastewater, wells, waste management, and oil and gas wells. G.S. 130A-22(a) describes administrative penalties related to the Solid Waste Management Act. G.S. 87-94 establishes maximum fines for violations of the Well Construction Act. G.S. 143-215.6A establishes maximum fines for violations under the Water & Air Resources Act. G.S. 113-410 sets penalties for violations of the oil & gas conservation act.

8. Any **right of appeal** for review of actions. [4.1.3.3]

- Solid waste: G.S. 150B-23 (referred to in G.S. 130A-22(e)
- G.S. 87-92 provides for appeals of any agency decision under the Well Construction Act.
- G.S. 143-215.5 provides for judicial review of any agency decision under the Water & Air Resources Act.

9. The **state contingency plan** for response to spills and releases, including volumes that trigger a response, time in which notification and clean-up is to occur, and criteria (i.e., cleanup standards) used to assure that remediation was accomplished. [4.2.1.1.a]

Under the State Emergency Management program, the State Emergency Operations Plan lists the hazardous materials plan which includes the response to hazardous materials, suspected hazardous materials and unknowns. That Tab of the State EOP is attached.

10. Any **funding** provisions to enable the state to respond to spills and releases in the event a responsible operator cannot be located or is unwilling or unable to respond, and any provisions for reimbursement of the state for monies so expended. [4.2.1.1.b]

The State of North Carolina calls upon the US EPA Emergency Response Program to mobilize federal contractors to assist in the response and remediation of spills as part of the National Contingency Plan.

11. Any mechanisms for the operators or public to report spills and releases. [4.2.1.2]

Reports are taken by the State Emergency Management personnel at the 24-7 State Emergency Operations Center. Their telephone number is 1-800-858-0368. In addition, operators or members of the public can contact local emergency services by dialing 911 or calling the National Response Center.

12. Any interagency **coordination of actions** between agencies having jurisdiction for response to spills and releases. [4.2.1.3]

Interagency coordination is described in the State EOP.

13. Any **requirements for operators** to prevent and respond to spills and releases. [4.2.1.4]

The conditions of the drilling permit are binding.

14. Any **general state contingency program elements** that address:
    a. Facilities, materials and equipment that may pose a significant threat. [4.2.1.4.1.a]
    b. The various environments at risk. [4.2.1.4.1.a]
    c. Measures to address public and responder safety concerns. [4.2.1.4.1.a]
    d. The operator's incident command structure. [4.2.1.4.1.b]
    e. Equipment, manpower and services to respond to spills and releases. [4.2.1.4.1.b]
    f. Opportunities for coordination of response actions. [4.2.1.4.1.b]
    g. Procedures for communication with threatened parties. [4.2.1.4.1.b]
    h. Methods of containment. [4.2.1.4.1.b]
    i. Methods of disposal of materials. [4.2.1.4.1.b]
    j. Responder training. [4.2.1.4.1.c]

A site-specific contingency plan may be required as a binding condition of the permit.

15. Any **spill prevention measures** that may include:
    a. Secondary containment measures. [4.2.1.4.2.a]
    b. Tertiary containment or monitoring systems in high risk areas. [4.2.1.4.2.b]
    c. Inspection, testing and maintenance procedures. [4.2.1.4.2.c]
    d. Site security measures as necessary. [4.2.1.4.2.d]
    e. Periodic review of opportunities to reduce future spills and releases. [4.2.1.4.2.e]

These may be specified by conditions in the permit.

16. Any **spill response measures** that may include:
    a. Agencies and parties to be notified. [4.2.1.4.3.a]
    b. Type of reporting (verbal, written) required. [4.2.1.4.3.a]
    c. Reporting time requirements. [4.2.1.4.3.a]
    d. Reporting thresholds. [4.2.1.4.3.a]
    e. Type of information to be reported. [4.2.1.4.3.a]

These may be specified by the conditions in the permit.

17. Any **state guidance for containment, abatement and remediation** of spills and releases including:

a. Clean-up standards. [4.2.1.4.3.b]
b. Required sampling and analyses. [4.2.1.4.3.b]
c. Any approved non-mechanical response actions. [4.2.1.4.3.b]

The Groundwater Classifications and Standards include general requirements for corrective action in 15A NCAC 2L .0106.

18. Any **final reporting, site monitoring requirements and necessary agency approvals** following the response to spills and releases. [4.2.1.4.3.c]

The Hazardous Materials Tab of the State EOP outlines these requirements.

19. Any **follow-up actions by the state**, including enforcement, assessment of damages, and reimbursement of costs for responding to spills and releases. [4.2.1.5]

The Hazardous Materials Tab of the State EOP outlines these requirements.

20. Any **database** that includes information on spills and releases. [4.2.1.6]

The Hazardous Materials Tab of the State EOP outlines these requirements.

21. Any **public participation** activities related to E&P environmental activities, such as public notice and comment requirements prior to permit issuance, availability of agency records for public review, public outreach to affected parties, and the use of any advisory groups. [4.2.2]

There are public notice allowances for wastewater and solid waste permits. G.S. Chapter 132 defines public records and sets requirements for their availability to the public. The specific rules for solid waste management can be found in15A NCAC 13A.0109, see (r), additional location standards for facilities, and 15A NCAC 13A.0109(r)(7)A-E. G.S. 143-215.1(c) specifies requirements for public hearings prior to the issuance of permits for discharges to surface waters.

22. The **program planning and evaluation process** including:
a. Any short-term and long-term strategic planning for regulatory development. [4.2.3.1]
b. Program evaluation of program effectiveness in protecting human health and the environment. [4.2.3.2.a]
c. Data management capabilities to enable assessment of program effectiveness and timeliness. [4.2.3.2.b]
d. Establishment of a baseline against which to compare future performance. [4.2.3.2.d]

As we do not yet have an established E&P program, we do not have program planning and evaluation yet. However, S.L. 2011-276 does direct DENR to study the potential oversight and administrative issues associated with an oil and gas regulatory program.

23. Any **financial assurance** requirements for E&P environmental regulatory activities or facilities, the activities for which financial assurance is required, the scope of coverage, the types of financial assurance instruments accepted, and procedures to access the assurance funds when necessary. [4.2.4]

The binding conditions of the drilling permit could include bonding of the company to address the financial assurance of the drilling company.

24. Any **waste hauler training and certification** requirements for commercial transportation of E&P wastes. [4.2.5]

None. Manifests must be available on site.

25. Any program relating to identification of the **location of closed disposal sites**, including any provisions making this information available for public review. [4.2.6]

Solid waste notice of inactive hazardous substance or waste disposal sites: G.S. 130A-310.8

26. The **data management** systems in place in your state for information related to E&P environmental regulatory program activities, including a description of the data elements, the extent to which the program utilizes electronic data management systems, and what information is or is not made available to the public. [4.2.7]

DLR:

Copies of all permits/reports for all oil and gas wells are maintained by DLR – N.C. Geological Survey and are available for public review under the public records laws of North Carolina.

DWM:

DWM has databases related to USTs available at: http://portal.ncdenr.org/web/wm/ust/database.

DWQ:

Basinwide Information Management System is used to track data on permits and compliance for the NPDES wastewater and stormwater, non-discharge wastewater, and UIC and well permitting programs. Nearly all data in this database is submitted on paper records and is entered manually, with the exception of a pilot project to provide electronic submission for some major NPDES permits. Under North Carolina public records law, all data within BIMS is publicly available upon request. DWQ makes available limited permit information from BIMS on its website.

Well Construction Database: Well drillers are required by 15A NCAC 2C .0114 to submit a well construction record to the Division of Water Quality for every well they drill. These records are entered into DENR's Well Construction Database and include information on the driller and well owner, well location, well construction characteristics, and driller's log. Data in this database is submitted on paper records and is entered manually,. Most of this information is subject to public disclosure upon request, but none is currently posted on the internet or otherwise made available without a request.

27. The **administrative support** assigned to the E&P environmental regulatory program, including the number, classifications, functions and duties, and minimum experience and training requirements for these positions, and any additional training that is made available to them. [4.3.1.1]

None currently assigned. Responsibilities carried out by program staff in multiple divisions.

28. How **legal support** is provided to the E&P environmental regulatory program. [4.3.1.2]

DENR Office of the General Council and the State Attorney General's office provide support to each division.

29. The **technical staff** assigned to provide geological or engineering support to the E&P environmental regulatory program, including the number, classifications, functions and duties and minimum experience and training requirements for these positions, and any additional training that is made available to them. [4.3.1.3]

None currently assigned. Responsibilities carried out by program staff in multiple divisions.

30. The **field personnel** assigned to conduct inspections and assure compliance with the E&P environmental regulatory program, including the number, classifications, functions and duties and minimum experience and training requirements for these positions, and any additional training that is made available to them. [4.3.1.4]

None currently assigned. Responsibilities carried out by program staff in multiple divisions.

31. Your program for **training** agency personnel on the regulations, policies and criteria applicable to E&P environmental regulatory activities. [4.3.1.5]

DLR's Erosion & Sedimentation Control has a concerted training program; otherwise, no formal training.

32. The methods used for **funding** the E&P environmental regulatory program in your state. [4.3.2]

Appropriations, permit fees, federal grants, portion of severance tax.

33. Any mechanisms to ensure **coordination among state agencies** on E&P environmental regulatory issues and, if your state has large tracts of federally administered public lands and/or tribal lands, any formal or informal mechanisms in which E&P environmental regulatory programs are coordinated with federal and/or Indian agencies. [4.4]

- The Interagency Leadership Team (ILT) is a group of agencies that have work sessions to identify concerns and issues facing transportation, the environment and the economy in North Carolina.
- Most of the regulatory programs are implemented under a single department (Radiation Protection, if involved, is the only exception).
- A 2007 MOA between DWM & DWQ specifies responsibilities of each division for managing contaminated sites.
- See previous section on EPA

III. TECHNICAL CRITERIA

A - GENERAL

1. Any **general performance or design standards** applicable to E&P waste management practices used in your state. [5.1.a]

Generic criteria would apply until specific E&P waste management criteria are developed.

2. Conditions, if any, under which disposal of E&P waste in **municipal solid waste landfills** allowed. [5.1.c]

Legislative changes or rulemaking would need to occur.

3. Provisions in the siting, construction or operation criteria for **variances**, **waivers**, **or other flexibility** to address site specific or regional conditions. [5.1.d]

N/A

4. Any **siting** criteria for E&P waste management facilities. [5.1.e]

Solid waste rules for issuing a permit to a hazardous waste facility.

Siting requirements that might apply to wastewater management or disposal facilities include:

- Riparian Buffer rules in 15A NCAC 2B apply to most development and require vegetated buffers to be maintained adjacent to surface waters in some river basins.
- Setbacks and water table separation requirements in 15A NCAC 2T for land application of wastewaters and wastewater treatment residuals.

5. Any **waste characterization** requirements, including sampling, analysis and quality control procedures. [5.2]

Solid Waste:

- Hazardous waste determination - 40 CFR 262.11 is adopted by reference at 15A NCAC 13A .0107.
- Standards for owners and operators of hazardous waste storage, treatment and disposal, including waste analysis plan for permitted facilities - 40 CFR 264.13 is adopted by reference at 15A NCAC 13A .0109

DWQ:

- 15A NCAC 2B .0103 specifies requirements for any chemical, physical, or biological analyses used to determine conformity with surface water standards.
- 15A NCAC 2T includes design criteria which specify wastewater quality requirements for each type of land-applied wastewater (e.g. 15A NCAC 2T .0505, Design Criteria for Wastewater Irrigation Systems).
- 15A NCAC 2U .0301 specifies effluent standards for reclaimed wastewater systems.

6. Any **air emission control** requirements applicable to E&P waste management facilities. [5.1.a and 5.10.2.2.c]

Air pollution control rules cover compressors over certain size, dehydration units for drying gas, drilling rigs, other heavy equipment, off-road general permits, etc. These rules are in 15A NCAC 2D.

7. Any programs promoting a **waste management hierarchy** that includes:
   a. source reduction opportunities. [5.3.1]
   b. recycling opportunities. [5.3.2]

The NC General Statutes spell out a standard waste management hierarchy that is the preferred method of waste management in the state, with source reduction first, followed by recycling and reuse, composting, incineration with energy recovery, incineration without energy recovery, and landfilling (see G.S. 130A-309.04). To our knowledge, there are no state statutes or policies that specifically promote source reduction and recycling for the oil and gas industry, such as specific requirements to adopt and implement such strategies, requirements for source reduction or recycling plans, reporting mechanisms on the use of source reduction or recycling techniques, or specific goals related to the reduction of oil and gas waste, especially as a condition of permitting. The Division of Environmental Assistance and Outreach has programs that provide technical assistance on the reduction and recycling of wastes and emissions, although to date the Division has had little experience with oil and natural gas operations and some of the resulting waste streams. Some generic waste streams possibly generated by oil and gas operations (e.g., waste oil, oil filters, and wooden pallets) are banned from solid waste disposal in North Carolina.

8. Any **program elements** that encourage E&P waste source reduction and recycling through policy, training, technical assistance or incentives. [5.3.3]

To our knowledge, there are no program elements that specifically pertain to oil and gas exploration and production. There would be opportunities to place in statute or as permitting and compliance conditions many of the source reduction and recycling best management practices articulated in the STRONGER 2010 Proposed Guidelines, but it seems the authority or ability to do so would possibly have to be created. The Hazardous Waste Section would address some of the liquid wastes that would result from oil and gas operations that would be deemed hazardous. We are not aware of any immediately available incentives to encourage adoption of source reduction and recycling techniques at oil and gas operations – those, too, may have to be created in statute and/or rules or policy. Reporting requirements would also seem critical to develop and implement.

B – PITS

As listed earlier, the master drilling permit application requires a site plan, drilling plan, drilling specification, and the location and size of proposed mud pits. The DLR in coordination with Waste Management, Water Quality, Air Quality and other federal agencies would put binding conditions on the drilling permit to address pits. That permit regulates mud pits. Conditions on the size, volume, lining, security, potential offsite disposal, chemical content, testing requirement of the pit contents and abandonment of pits are part of the drilling permit. In law, drilling cannot start until the pits have been installed to the satisfaction of the regulatory agency.

9. Technical criteria for **pits**. [5.5.1]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

10. How pits are **permitted**. [5.5.2.a]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

11. If pits are **permitted by rule,** any requirements or limitations that are applicable. [5.5.2.b]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

12. Whether pits are **permitted individually** and/or as part of **facility**, **operational or general permits**. [5.5.2.c]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

13. Any **notification** required prior to construction and operation of rule-authorized pits. [5.5.2.d]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

14. Any provisions concerning the issuance and use of **emergency permits** for pits. [5.5.2.e]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

15. Any requirements included in statewide regulations regarding the size, depth, berm height and other **construction** parameters for pits. [5.5.3.a]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

16. Any requirements to assure that there is no adverse **impact to ground water or surface waters** from use of the pit. [5.5.3.b]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

17. Any requirements to assure **structural integrity** of pits. [5.5.3.c]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

18. How construction requirements assure that pits are designed to accommodate **fluids** which are intended to be contained in them. [5.5.3.d]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

19. If construction standards for pits differ depending on the **waste characteristics** of materials they are to receive, the circumstances under which variances or special conditions are used. [5.5.3.e]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

20. Conditions under which **pit liners** or **tanks** are required in lieu of pits. [5.5.3.e]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

21. Any requirements for **fencing**, **netting and caging** of pits. [5.5.3.f]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

22. Any requirements for the **placement of reserve pits** relative to drilling equipment. [5.5.3.g]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

23. Any restrictions placed on the **type and characteristics of wastes** that can be placed in pits. [5.5.4.a]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

24. Any **security** guidelines or requirements are in place regarding pits. [5.5.4.b]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

25. Any requirements for maintaining a **freeboard** level in pits and how is this level calculated. [5.5.4.c]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

26. How **liner integrity** is maintained and assured in lined pits. [5.5.4.d]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

27. Any routine **inspections or monitoring and reporting** required by the operator to assure that pit operational and structural integrity requirements are being met. [5.5.4.e]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

28. Any requirements for the **removal/disposal/recycling of hydrocarbons** that accumulate in pits. [5.5.4.f]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

29. Any requirements for the **removal of separated oil or wastes** from unlined skimming/settling pits. [5.5.4.g]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

30. If **produced water pits** are allowed in your state, the requirements for disposal of the water? [5.5.4.h]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

31. Any restrictions concerning the use of **percolation pits**. [5.5.4.i]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

32. Any maintenance requirements for **evaporation pits**. [5.5.4.j]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

33. Any restrictions placed on the use of **emergency pits**, and any notification of the regulatory agency and removal of fluids required when they are used. [5.5.4.k]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

34. Any prohibition against the use of **unlined basic sediment pits** for oily wastes. [5.5.4.l]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

35. Any limitations placed on the operation of **workover pits.** [5.5.4.m]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

36. Any time limit placed on the **closure of reserve pits**. [5.5.5.b]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

37. Any **testing of pit liquids is required before pit closure**, and if on-site disposal of pit liquids is authorized, what criteria apply to such disposal. [5.5.5.c]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

38. Conditions under which pit **liquids must be removed** before closure. [5.5.5.d]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

39. The requirements for **closure and reclamation** of pit sites. [5.5.5.e]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

40. The **records** to be kept of pit sites and their availability to the public. [5.5.5.f]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

C - LANDSPREADING (Non-Commercial)

41. Any **criteria for landspreading** of E&P wastes. [5.6.1.b]

If there were landspreading of drilling wastes, this activity could be subject to permitting under either Soil Remediation in 15A NCAC 2T .1500 or possibly as a Residual under 15A NCAC 2T .1100. This scenario does not fit perfectly into either of these two categories, but we have precedents of flexibility for other waste streams. Soil remediation permits are issued by either the UST Section of DWM or the Aquifer Protection Section of DWQ, depending on the source of the waste. At this time, approvals would be required for each landspreading event. Residuals permits are issued by the Aquifer Protection Section of DWQ. Statutory authority of G.S. 143-215.1 applies in either case.

42. Any prohibitions on **landspreading of waste containing NORM** above action levels. [5.6.1.c]

Unknown.

43. Any **operational requirements** applicable to landspreading. [5.6.3]

The UST Section of DWM regulates land farming in the state, and at this time, approvals would be required for each event.

D - BURIAL AND LANDFILLING (Non-Commercial)

44. Any **regulatory requirements** for burial or landfilling of E&P wastes. [5.7.2]

These requirements would have to be created by legislation or rulemaking. Landfills do not currently accept petroleum wastes.

Neither oil nor oil filters can be disposed of in landfills in North Carolina.

45. Any **operational requirements** applicable to burial or landfilling. [5.7.3]

See question 44.

E – ROADSPREADING

46. Any **regulatory criteria** for roadspreading of E&P wastes. [5.8.2]

Roadspreading of produced waters or other E&P wastewaters would be subject to permitting as a reclaimed water system under 15A NCAC 2U.

47. Any **operational requirements** applicable to roadspreading. [5.8.3]

Roadspreading of produced waters or other E&P wastewaters would be subject to design criteria, utilization requirements, and requirements for operational plans for reclaimed water systems in 15A NCAC 2U.

F – TANKS

48. Any requirements pertaining to the **location**, **use**, **capacity**, **age and construction of E&P waste tanks**, including registration, inventories, etc. [5.9.2.a]

This will be determined on a case by case basis in coordination with the Division of Waste Management and the Division of Water Quality. Solid waste: hazardous waste permits (40 CFR 270.14(b)(1) and 270.16 are adopted by reference at 15A NCAC 13A.0113)

49. Any state program pertaining to **pollution prevention requirements relating to tanks**. [5.9.2.c]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

50. Any **construction and operation requirements** applicable to E&P waste tanks. [5.9.3]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

51. Any tank **removal and closure** requirements. [5.9.4]

This will be determined on a case by case basis by DLR in coordination with the Division of Waste Management and the Division of Water Quality.

As listed earlier, the master drilling permit application requires a site plan, drilling plan, drilling specification, and the location and size of proposed tanks. The DLR in coordination with Waste Management, Water Quality, Air Quality and other federal agencies would put binding conditions on the drilling permit to address tanks. Conditions on the size, volume, lining, security, potential offsite disposal, chemical content, testing requirement of the pit contents and abandonment of tanks are part of the drilling permit. In law, drilling cannot start until the tanks necessary to support the drilling have been installed to the satisfaction of the regulatory agency.

G - COMMERCIAL AND CENTRALIZED DISPOSAL FACILITIES

There are no specific facilities now, but DWM would be responsible if any were developed/proposed.

52. Which agency (agencies) has (have) regulatory **jurisdiction** over these facilities. [5.10.1]

The Division of Waste Management.

53. If you have any centralized or commercial E&P waste disposal facilities, **how many**, **and of what type**, and how many are associated with UIC sites. [5.10.1]

There are none associated with UIC Class II sites.

54. The **regulatory requirements** related to permits, acceptable types and volumes of wastes, and waste characteristics as related to disposal facility compatibility. [5.10.2]

The attached document, Landfill Requirements Disposal Facility, outlines these requirements.

55. A description of **what wastes are acceptable** for disposal (i.e., do any of these facilities accept RCRA nonexempt wastes or wastes from other than oil and gas exploration and production activities). [5.10.2]

Yes, North Carolina facilities accept RCRA nonexempt wastes.

56. The **disposal and treatment methods** employed at these facilities. [5.10.2]

North Carolina does not have any commercial disposal facilities. Treatment methods employed by commercial facilities in North Carolina include:

- Aqueous inorganic treatment
- Aqueous organic treatment
- Energy recovery
- Fuel blending
- Incineration
- Land treatment/application/farming
- Landfill/surface impoundment
- Metals recovery
- Other treatment
- Sludge treatment
- Solvents recovery
- Stabilization
- Storage and/or transfer

57. The elements required as part of the **permit** application (e.g., siting plan, construction plan, operating plan, closure plan, etc.). [5.10.2.2.a]

See the attached document "Permitting Requirements."

58. Any permit application requirements for **siting**. [5.10.2.2.b]

Yes. There are requirements for issuing a permit to a hazardous waste facility, described in the following locations:

- Location standards are listed in: http://portal.ncdenr.org/web/wm/hw/rules/addrequirments#additionallocationstandards.
- Areas where a hazardous waste landfill, long-term storage, or a surface impoundment facility cannot be located are listed in: 15A NCAC 13A .0109(r)(4)(A)
- Minimum separation distances for hazardous waste facilities are found in: 15A NCAC 13A.0109(r)(2)(C)
- A requirement to make monthly reports is found in GS 130 A-294(c)(18)

59. Any **construction** requirements that will minimize or prevent releases to surface water, ground water, soil and air. [5.10.2.2.c]

40 CFR 270.21(b) requirements are incorporated by reference at 15A NCAC 13A .0113

and 40 CFR 264.301(d) and 40 CFR 264.301(e) requirements are incorporated by reference at 15A NCAC 13A .0109.

60. Any permit application requirements for **operating**. [5.10.2.2.d]

See the attached Contingency Plan, Inspection Requirements, and Waste Analysis documents.

61. Any **closure and post-closure monitoring** and maintenance requirements, including duration of post-closure care and financial assurance release schedules. [5.10.2.2.e]

See the attached Closure and Post Closure document.

62. For wastes not moved by pipeline, any requirements for **waste tracking**. [5.10.2.3]

Waste tracking is done by using the manifest system that inspectors review during an inspection.

63. Any **waste haulers** permitting or licensing program. [5.10.2.3]

Transporters of hazardous waste are required to get an EPA Identification Number: http://www.epa.gov/osw/inforesources/data/form8700/forms.htm.

IV. ABANDONED SITES

1. Any state program to **inventory**, **prioritize and remediate** (as necessary) abandoned oil and gas sites. [6.1]

There are no abandoned oil and gas sites in the State. If we had one we would seal it as the Oil and GAS Conservation Act requires for all wells – it is sealed completely from the bottom to the top.

2. Reference to any **definitions** pertaining to abandoned sites or your abandoned well site program, including the types of facilities included in the definitions. [6.2]

There are definitions in the Oil & Gas Conservation Act (G.S. 113 Article 27). Some of these are available at G.S. 113-27, but the S.L. 2011-276 additions are:

> Unless the context otherwise requires, the words defined in this section shall have the following meaning when found in this law:
>
> (7a) "Oil and gas developer or operator" or "developer or operator" shall mean a person who acquires a lease for the purpose of conducting exploration for or extracting oil or gas.

(7b) "Oil and gas operations" or "activities" shall mean the exploration for or drilling of an oil and gas well that requires entry upon surface estate and the production operations directly related to the exploration or drilling.
(15) "Surface owner" means the person who holds record title to or has a purchaser's interest in the surface of real property.

3. Your program for **identification**, **inventory and ranking** of abandoned sites. [6.3]

None

4. Any **funding** mechanisms available to the state for abandoned site remediation. [6.4]

None

5. The criteria used in your **abandoned site prioritizing** system. [6.5]

None

6. The state's abandoned site remediation **goals** and how progress is measured. [6.5.1]

None

7. The state's program relating to establishing **liability** for the remediation of abandoned sites. [6.5.2]

None

8. Any **standards for abandoned site remediation**. [6.6]

9. The state's **abandoned well remediation** program, including any flexibility allowed in plugging procedures. [6.6.1]

10. The state's program for **surface remediation** of abandoned sites, including any requirements regarding present or future land use and consultation with surface owners. [6.6.2]

11. The program for **maintenance of records** of remediated sites, including public access. [6.6.3]

Regulatory records are required to be maintained and available for the public under the North Carolina public records law. Oil and Gas files are maintained by the N.C. Geological Survey and are filled by location in file cabinets at the NCGS Field Office and Core Repository. When abandoning a well, a log of the drilling and development of each well is required by G.S. 113-379. G.S. 113-391requires a reasonable bond condition for the performance of the duty to plug each dry or abandoned well. G.S. 113-395, as amended by S.L. 2011-276, requires notice that the well is to be abandoned and requires a $450 fee.

12. Any **public participation** activities associated with the abandoned sites program, including public access to information, public participation in rulemaking

associated with the program, and participation regarding the priority of sites on the inventory and level of remediation. [6.7]

V. NATURALLY OCCURRING RADIOACTIVE MATERIAL

1. Any activities the state has undertaken to determine the **occurrence and need for regulation** of NORM. [7.2]

Study under H242 will include testing for NORM.

2. Any **program elements** applicable to the NORM regulatory program, including:
   a. Definitions. [7.3.1]
   b. Action levels. [7.3.2]
   c. Surveys. [7.3.3]
   d. Worker protection. [7.3.4]
   e. Licensing/permitting. [7.3.5]
   f. Removal/remediation standards. [7.3.6]
   g. Storage. [7.3.7]
   h. Transfer for continued use. [7.3.8]
   i. Release of sites, materials and equipment. [7.3.9]
   j. Disposal. [7.3.10]
   k. Interagency coordination. [7.3.11]
   l. Public participation. [7.3.12]

The Radiation Protection Section of the Division of Public Health in the Department of Health and Human Services does not regulate NORMs. Existing state laws do not allow RPS to regulate NORMs unless the radioactivity exceeds an action level. The action level differs for each radioactive element. Should the NORMs be concentrated by natural means above the action level, shielding to protect persons from accidentally exposing themselves would be required. Should NORMs be concentrated by mechanical or chemical means above the action level, that process of concentration would require a permit from RPS.

VI. STORMWATER MANAGEMENT

1. Any state program for the **management of storm water** and the basis for its development. [8.1]

North Carolina implements the following state programs for stormwater management:

- The federal NPDES Phase I permitting program for stormwater discharges from industrial activities.
- The federal NPDES Phase I permitting program for stormwater discharges from construction activities.
- The federal NPDES Phase I and Phase II stormwater permitting programs for local governments operating MS4s.
- A state post-construction stormwater permitting program for new development

not captured by the NPDES Phase II program but within certain areas.

- A state stormwater management permitting program for new development in the 20 coastal counties and especially protected waters including Outstanding Resource Waters and High Quality Waters (under S.L. 2008-211).
- State rules for the protection of Nutrient Sensitive Waters are applicable to several river basins and large reservoirs in the state and establish protective restrictions on stormwater discharges to be implemented by local jurisdictions.
- A state program supporting the protection of Water Supply Watersheds that includes some elements for stormwater management. Implemented by local governments; audited by DWQ
- Stormwater requirements are frequently included in the state 401 certification for the protection of wetlands.

The state stormwater program is implemented under G.S. 143-214.7 to regulate site development and post-construction stormwater runoff control. Stormwater Management rules in 15A NCAC 2H .1000 have been adopted in order to implement the state program. Areas subject to these permit programs include all 20 coastal counties, and various other counties and watersheds (such as water supply watersheds, high quality waters, and outstanding resource waters) throughout the state. While the state program does not specifically refer to hydrocarbon exploration and production, certain provisions may apply when these operations are located in the areas subject to the state program. The state has authority to require corrective action for conditions causing violations of a water quality standard even if the activity is not covered by an existing program; however, this authority can only be used after standard violation has occurred.

Under Session Law 2006-246, the Phase II program builds upon the existing Phase I program by requiring certain smaller communities (<100,000) and public entities that own and operate a municipal separate storm sewer system (MS4) to apply and obtain an NPDES permit for stormwater discharges. Certain urbanized areas of counties are also regulated by this law. The session law defines the communities that are required to obtain a Phase II permit, the process for including new communities, and the general requirements for compliance with a Phase II permit. Each community that is subject to Phase I and Phase II is required to meet the following six minimum measures:

- Public education and outreach on stormwater impacts.
- Public involvement/participation.
- Illicit discharge detection and elimination.
- Construction site stormwater runoff control.
- Post-construction stormwater management in new development and redevelopment.
- Pollution prevention/good housekeeping for municipal operations.

In addition to the state program, Section 401 of the Clean Water Act delegates authority to the states to issue a 401 Water Quality Certification for all projects that require a Federal Section 404 Permit due to impacts to wetlands or waters of the State. A 401 Water Quality Certification is also required to impact isolated wetlands, which are not covered under Section 404. The 401 Certification is verification by the Division of Water

Quality that a given project will not degrade waters of the State or otherwise violate water quality standards. The rules for issuance of a 401 certification are found in 15A NCAC 02H .0500. These rules and the stormwater requirements associated with receiving a 401 Certification can be found on the Division of Water Quality's web site at: http://portal.ncdenr.org/web/wq/swp/ws/401.

2. Any state regulatory **program mechanisms** for storm water management or erosion control such as permits/authorizations, compliance evaluation, outreach and training, and program evaluation. [8.2]

Erosion and sedimentation control permits, as described on pages 10 and 11. North Carolina has adopted requirements for stormwater permits for new development in 15A NCAC 2H.1000. In addition, as mentioned above, each MS4 that is subject to Phase I and Phase II is required to meet the following six minimum measures:

a. Public education and outreach on stormwater impacts.
b. Public involvement/participation.
c. Illicit discharge detection and elimination.
d. Construction site stormwater runoff control.
e. Post-construction stormwater management in new development and redevelopment.
f. Pollution prevention/good housekeeping for municipal operations.

3. Any regulatory **program criteria**, including:

a. Planning requirements with respect to site development. [8.3.1]
b. Construction standards or management practices appropriate for the area. [8.3.2]
c. Operation and maintenance measures to control sediment until the site is restored. [8.3.3]
d. Restoration and reclamation standards. [8.3.4]

The erosion & sedimentation control design manual addresses all of these.

Under Session Law 2006-246, Phase II local governments are required to implement stormwater planning requirements for site development, construction standards and best management practices, and post-construction stormwater management measures. Requirements within the 20 coastal counties are described in S.L. 2008-211.

All surface waters in North Carolina are classified as to best use. Some classifications are especially protected, and there are restrictions on development in the contributing watersheds and/or restrictions as to permissible stormwater or wastewater pollutant discharges. Discharges may be restricted based on classifications: Outstanding Resource Waters, High Quality Waters, Trout Waters, Water Supply I – V, Critical Area, Shellfishing Waters, Nutrient Sensitive Waters, and zero-flow streams.

In addition to broad restrictions based on classification, some few waters in North Carolina have special management strategies in place that may limit allowable stormwater or wastewater discharges. Special management strategies are tabulated in North Carolina regulations at 15A NCAC 2B .0200.

In addition, stream segments with threatened or endangered species, both on the federal list and the North Carolina list, may be subject to additional constraints on discharges.

VII. HYDRAULIC FRACTURING

1. Has the state evaluated potential **risks associated with hydraulic fracturing**, taking into account factors such as depth of the reservoir to be fractured, proximity of the reservoir to fresh water resources, well completion practices, well design, and volume and nature of fluids? [9.2]

No. A study is currently underway.

2. Has the state developed **standards to prevent the contamination** of groundwater and surface water from hydraulic fracturing? [9.2]

Injection well rules currently prohibit injection pressures from initiating or propagating fractures.

3. Describe how state standards for **casing and cementing** meet anticipated pressures associated with hydraulic fracturing to protect other resources and the environment. [9.2.1]

Current casing & cementing standards were not developed with hydraulic fracturing in mind.

4. Discuss how the program identifies and, where deemed appropriate, manages risks associated with **potential conduits for fluid migration** in the area of hydraulic fracturing. [9.2.1]

N/A – all hydraulic fracturing is currently prohibited.

5. Describe program requirements that address actions to be taken in **response to unanticipated operational or mechanical changes** encountered during hydraulic fracturing that may cause concern. [9.2.1]

N/A – all hydraulic fracturing is currently prohibited.

6. Briefly describe how **surface controls** associated with hydraulic fracturing, such as dikes, pits or tanks, meet Sections 5.5 and 5.9 of the guidelines. [9.2.1]

The master drilling permit application requires a site plan, drilling plan, drilling specification, and the location and size of proposed mud pits. The DLR in coordination with Waste Management, Water Quality, Air Quality and other federal agencies would put binding conditions on the drilling permit to address pits and tanks. That permit regulates mud pits. Conditions on the size, volume, lining, security, potential offsite disposal, chemical content, testing requirement of the pit contents and abandonment of pits and tanks are part of the drilling permit. In law, drilling cannot start until the pits and tanks have been installed to the satisfaction of the regulatory agency.

7. Briefly describe how **contingency planning and spill risk management** procedures related to hydraulic fracturing meet Section 4.2.1 of the guidelines. [9.2.1]

N/A

8. Briefly discuss how hydraulic fracturing **waste characterization requirements**, including, as appropriate, testing of fracturing fluids, are consistent with Section 5.2 of the guidelines. [9.2.1]

N/A

9. Briefly describe how the **waste management hierarchy** contained in Section 5.3 of the guidelines (source reduction, recycling, treatment and disposal), including the provisions relating to toxicity reduction, are promoted for hydraulic fracturing. [9.2.1]

N/A

10. Briefly describe how the **tracking of hydraulic fracturing waste** disposed at commercial or centralized facilities meets the requirements of Section 5.10.2.3 of the guidelines. [9.2.1]

N/A

11. Briefly describe how procedures in place for receipt of **complaints** related to hydraulic fracturing are consistent with Section 4.1.2.1 of the guidelines. [9.2.1]

N/A

12. Describe any required **notification** prior to, and reporting after completion of hydraulic fracturing operations. [9.2.2]

N/A

13. Is notification sufficient to allow the **presence of field staff** to monitor hydraulic fracturing activities? [9.2.2]

N/A

14. Describe **reporting requirements** for hydraulic fracturing activities and whether they include the identification of materials used, aggregate volumes of fracturing fluids and proppant used, and fracture pressures recorded. [9.2.2]

N/A

15. Describe any mechanisms for **disclosure of information on chemical constituents** used in hydraulic fracturing fluids to the state in the event of an investigation or to medical personnel in the event of a medical emergency. [9.2.2]

N/A

16. Briefly describe how hydraulic fracturing information submitted that is of **a confidential business nature**, is treated consistent with Section 4.2.2 of the guidelines. [9.2.2]

Not currently applicable, but G.S. 132-1.2 specifies the characteristics of information that is not subject to public disclosure.

17. Briefly discuss if, in addition to the personnel and funding recommendations found in Section 4.3 of the guidelines, **state staffing levels** sufficient to receive, record and respond to complaints of human health impacts and environmental damage resulting from hydraulic fracturing. [9.2.3]

N/A

18. Describe staff **training** to stay current with new and developing hydraulic fracturing technology. [9.2.3]

None

19. Briefly describe how the state agency provides for **dissemination of educational information** regarding well construction and hydraulic fracturing to bridge the knowledge gap between experts and the public as provided in Section 4.2.2.2 of the guidelines. This is especially important in areas where development has not occurred historically and in areas where high volume water use for hydraulic fracturing is occurring. [9.2.4]

None

20. Fundamental differences exist from state to state, and between regions within a state, in terms of geology and hydrology. Describe how the state evaluated and addressed, where necessary, the **availability of water for hydraulic fracturing** in the context of all competing uses and potential environmental impacts resulting from the volume of water used for hydraulic fracturing. [9.3]

Under review; to be determined by DWR as part of required study under H242.

21. Describe how the availability and use of alternative water sources for hydraulic fracturing, including recycled water, is encouraged. [9.3]

N/A

22. Briefly describe how **waste** associated with hydraulic fracturing is managed consistent with Section 4.1.1 and Section 7 of the guidelines. [9.3]

N/A

23. Discuss how the state encourages the efficient development of adequate **capacity and infrastructure** for the management of hydraulic fracturing fluids, including the transportation, recycling, treatment and disposal of source water and hydraulic fracturing wastes. [9.3]

GENERAL ASSEMBLY OF NORTH CAROLINA
SESSION 2011

SESSION LAW 2011-276
HOUSE BILL 242

AN ACT TO (1) INCREASE THE AMOUNT OF THE BOND REQUIRED UPON REGISTRATION IN ORDER TO DRILL FOR OIL OR NATURAL GAS IN THE STATE; (2) INCREASE THE AMOUNT OF FEES APPLICABLE TO DRILLING AND ABANDONING OIL OR GAS WELLS; (3) ESTABLISH PROVISIONS FOR THE PROTECTION OF LANDOWNERS RELATIVE TO LEASES FOR OIL AND GAS EXPLORATION; (4) DIRECT THE DEPARTMENT OF ENVIRONMENT AND NATURAL RESOURCES TO STUDY THE ISSUE OF OIL AND GAS EXPLORATION IN THE STATE, AND SPECIFICALLY THE USE OF DIRECTIONAL AND HORIZONTAL DRILLING AND HYDRAULIC FRACTURING FOR THAT PURPOSE; AND (5) DIRECT THE DEPARTMENT OF ENVIRONMENT AND NATURAL RESOURCES TO CONDUCT AT LEAST TWO PUBLIC HEARINGS ON THE ISSUE IN THE AREA IN WHICH EXPLORATION FOR NATURAL GAS BY MEANS OF DIRECTIONAL AND HORIZONTAL DRILLING AND HYDRAULIC FRACTURING MAY OCCUR.

The General Assembly of North Carolina enacts:

SECTION 1. G.S. 113-378 reads as rewritten:

"**§ 113-378. Persons drilling for oil or gas to register and furnish bond.**

Any person, firm or corporation before making any drilling exploration in this State for oil or natural gas shall register with the Department of Environment and Natural ~~Resources or such other State agency as may hereafter be established to control the conservation of oil or gas in this State.~~<u>Resources.</u> To provide for such registration, the drilling operator must furnish the name and address of such person, firm or corporation, and the location of the proposed drilling operations, and file with the ~~aforesaid~~ Department a bond in ~~the~~ <u>an</u> amount <u>totaling the sum of</u>~~of~~ <u>(i)</u> five thousand dollars <u>($5,000) plus (ii) one dollar ($1.00) per linear foot proposed to be drilled for the well.</u> ~~($5,000) running to the State of North Carolina, conditioned that any~~ <u>Any</u> well opened by the drilling operator ~~upon abandonment~~ shall be plugged <u>upon abandonment</u> in accordance with the rules of ~~said~~ <u>the</u> Department."

SECTION 2. G.S. 113-395 reads as rewritten:

"**§ 113-395. Notice and payment of fee to Department before drilling or abandoning well; plugging abandoned well.**

Before any well, in search of oil or gas, shall be drilled, the person desiring to drill the same shall notify the Department upon such form as it may prescribe and shall pay a fee of ~~fifty~~ <u>three thousand</u> dollars ~~($50.00)~~<u>($3,000)</u> for each well. The drilling of any well is hereby prohibited until such notice is given and such fee has been paid and permit granted.

Each abandoned well and each dry hole ~~promptly~~ shall be plugged <u>promptly</u> in the manner and within the time required by rules ~~to be~~ prescribed by the Department, and the owner of such well shall give notice, upon such form as the Department may prescribe, of the abandonment of each dry hole and of the owner's intention to abandon, and shall pay a fee of ~~fifteen~~ <u>four hundred fifty</u> dollars ~~($15.00)~~<u>($450.00)</u>. No well shall be abandoned until such notice has been given and such fee has been paid."

SECTION 3.(a) G.S. 113-389 reads as rewritten:

"**§ 113-389. Definitions.**

Unless the context otherwise requires, the words defined in this section shall have the following meaning when found in this law:

…

H242-V-7

(7a) "Oil and gas developer or operator" or "developer or operator" shall mean a person who acquires a lease for the purpose of conducting exploration for or extracting oil or gas.

(7b) "Oil and gas operations" or "activities" shall mean the exploration for or drilling of an oil and gas well that requires entry upon surface estate and the production operations directly related to the exploration or drilling.

…

(15) "Surface owner" means the person who holds record title to or has a purchaser's interest in the surface of real property.

…."

SECTION 3.(b) Article 27 of Chapter 113 of the General Statutes is amended by adding a new Part to read:

"Part 3. Landowner Protection.

"**§ 113-420. Notice and entry to property.**

(a) If an oil and gas developer or operator is not the surface owner of the property on which oil and gas operations are to occur, before entering the property for oil and gas operations that do not disturb the surface, including inspections, staking, surveys, measurements, and general evaluation of proposed routes and sites for oil and gas drilling operations, the developer or operator shall give written notice to the surface owner at least seven days before the desired date of entry to the property. Notice shall be given by certified mail, return receipt requested. The requirements of this subsection may not be waived by agreement of the parties. The notice, at a minimum, shall include all of the following:

(1) The identity of person(s) requesting entry upon the property.

(2) The purpose for entry on the property.

(3) The dates, times, and location on which entry to the property will occur, including the estimated number of entries.

(b) If an oil and gas developer or operator is not the surface owner of the property on which oil and gas operations are to occur, before entering the property for oil and gas operations that disturb the surface, the developer or operator shall give written notice to the surface owner at least 14 days before the desired date of entry to the property. Notice shall be given by certified mail, return receipt requested. The notice, at a minimum, shall include all of the following:

(1) A description of the exploration or development plan, including, but not limited to (i) the proposed locations of any roads, drill pads, pipeline routes, and other alterations to the surface estate and (ii) the proposed date on or after which the proposed alterations will begin.

(2) An offer of the oil and gas developer or operator to consult with the surface owner to review and discuss the location of the proposed alterations.

(3) The name, address, telephone number, and title of a contact person employed by or representing the oil or gas developer or operator who the surface owner may contact following the receipt of notice concerning the location of the proposed alterations.

(c) If the oil and gas developer or operator fails to give notice as provided in this section, the surface owner may seek appropriate relief in the superior court for the county in which the oil or gas well is located and may receive actual damages.

"**§ 113-421. Compensation for damages.**

(a) The oil and gas developer or operator shall be obligated to pay the surface owner compensation for all of the following:

(1) Any damage to a water supply in use prior to the commencement of the activities of the developer or operator which is due to those activities.

(2) The cost of repair of personal property of the surface owner, which personal property is damaged due to activities of the developer or operator, up to the value of replacement by personal property of like age, wear, and quality.

(b) When compensation is required, the surface owner shall have the option of accepting a one-time payment or annual payments for a period of time not less than 10 years.

(c) The surface owner has the right to seek damages pursuant to this section in the superior court for the county in which the oil or gas well is located. The superior court for the county in which the oil or gas well is located has jurisdiction over all proceedings brought pursuant to this section. If the surface owner or the surface owner's assignee is the prevailing party in an action to recover unpaid royalties, the court shall award any court costs and reasonable attorneys' fees to the surface owner or the surface owner's assignee.

(d) Conditions precedent, notice provisions, or arbitration clauses included in lease documents that have the effect of limiting access to the superior court in the county in which the oil or gas well is located are void and unenforceable.

"**§ 113-422. Indemnification.**

An oil or gas developer or operator shall indemnify a surface owner for damage to property that is adjacent to property on which drilling occurs, as well as adjacent infrastructure, and wells.

"**§ 113-423. Maximum lease terms.**

Any lease of oil or gas rights or any other conveyance of any kind separating rights to oil or gas from the freehold estate of surface property shall expire at the end of 10 years from the date the lease is executed, unless, at the end of the 10-year period, oil or gas is being produced for commercial purposes from the land to which the lease applies. If, at any time after the 10-year period, commercial production of oil or gas is terminated for a period of six months or more, all rights to the oil or gas shall revert to the surface owner of the property to which the lease pertains. No assignment or agreement to waive the provisions of this subsection shall be valid or enforceable. As used in this subsection, the term "production" includes the actual production of oil or gas by a lessee, or when activities are being conducted by the lessee for injection, withdrawal, storage, or disposal of water, gas, or other fluids, or when rentals or royalties are being paid by the lessee.

"**§ 113-424. Applicability; effect.**

This Part applies to leases or contracts, and amendments to leases or contracts, entered into on or after June 15, 2011."

SECTION 4. The Department of Environment and Natural Resources, the Department of Commerce as specifically directed by subdivision (5) of this section, and the Consumer Protection Division of the Department of Justice as specifically directed by subdivision (8) of this section shall study the issue of oil and gas exploration in the State and the use of directional and horizontal drilling and hydraulic fracturing for that purpose. The Department of Environment and Natural Resources, in conjunction with the Department of Commerce and the Consumer Protection Division of the Department of Justice, shall report their findings and recommendations, including specific legislative proposals, to the Environmental Review Commission no later than May 1, 2012. At a minimum, the study shall include information on the following:

(1) Oil and gas resources present in the Triassic Basins and in any other areas of the State.

(2) Methods of exploration and extraction of oil and gas, including directional and horizontal drilling and hydraulic fracturing.

(3) Potential impacts on infrastructure, including roads, pipelines, and water and wastewater services. In analyzing potential impacts, the Department shall specifically examine the expected water usage from hydraulic fracturing, water resources in the area in which drilling may occur, as well as existing water users in the area that may be impacted by increased consumption of water for use in hydraulic fracturing.

(4) Potential environmental impacts, including constituents or contaminants that may be present in the fluid used in the hydraulic fracturing process; the potential for the contamination of nearby wells and groundwater, as well as the options for disposal and reuse of the wastewater produced; stormwater management; the potential for emission of toxic air pollutants; impacts on wildlife; management and reclamation of drilling sites, including orphaned sites; management of naturally occurring radioactive materials (NORM) generated by the drilling and production of natural gas; and the potential for seismic activity in the area in which drilling may occur. In examining this issue, the Department shall formulate regulatory requirements advisable to address potential environmental impacts and in doing so shall gather information on regulatory programs in other states where oil and gas exploration or extraction is occurring, particularly with regard to the use of hydraulic fracturing for that purpose.

(5) Potential economic impacts, including possible sources of revenue that could accrue to the benefit of the State in the event that drilling for oil or natural gas were to take place in the State. In examining this issue, the Department of Commerce, in consultation with the Department of Environment and Natural Resources, shall gather information on (i) the number of jobs that may be expected as a result from drilling activities in the State and (ii) what severance taxes, fees, royalties, bonds, or assessments may be appropriate in connection with the activity. For any sources of revenue that may be anticipated, the Department of Commerce, in consultation with the Department of Environment and Natural Resources, shall evaluate use of the revenue for the following purposes: funds necessary to implement an oil and gas regulatory program; funds dedicated to the conservation and preservation of land and water resources; funds dedicated to remediation of environmental contamination such as the Inactive Hazardous Sites Cleanup Fund; and funds dedicated to improving water and wastewater infrastructure across the State.

(6) Potential social impacts, including impacts of drilling operations on nearby communities and quality of life within those communities, recreational activities, and commercial and residential development.

(7) Potential oversight and administrative issues associated with an oil and gas regulatory program, including statutory authority necessary for implementation of such a program; funding requirements necessary to implement a stable and effective program; criteria for permit issuance or denial; frequency and scope of inspections; compliance and enforcement procedures; coordination of agency involvement to ensure efficient permitting and clear delineation of compliance responsibilities; opportunities for public participation; and data management.

(8) Consumer protection and legal issues relevant to oil and gas exploration in the State, including matters of contract and property law, mineral leases, and landowner rights. In examining these issues, the Consumer Protection Division of the Department of Justice, in consultation with the Department of Environment and Natural Resources, shall specifically examine appropriate provisions on recommended disclosures to landowners, compensation for damages, payment of royalties, and remedies for breach, and any other matters the Division deems relevant. The Division shall also study such issues in consultation with the Rural Advancement Foundation International (RAFI).

(9) Any other pertinent issues that the Department deems relevant to oil and gas exploration in the State and the use of hydraulic fracturing for that purpose.

SECTION 5. By February 1, 2012, the Department of Environment and Natural Resources shall hold at least two public hearings at separate locations within the Triassic Basin on the issue of drilling for natural gas by means of directional and horizontal drilling and hydraulic fracturing. The public hearings shall be conducted in order to promote awareness of the issue generally and inform and consult with the public and user groups on potential environmental impacts, potential regulatory controls, potential economic impacts, and consumer protection issues, including landowner rights and mineral leases. In developing the consumer protection portion of the public hearings, the Department shall consult with the Consumer Protection Division of the North Carolina Department of Justice and the Rural Advancement Foundation International (RAFI).

SECTION 6. In order to avoid redundancy and to make the most efficient use of State resources, the Department of Environment and Natural Resources and the Energy Jobs Council shall, to the maximum extent practicable, conduct the study required by Section 4 of this act in conjunction with the study required by Section 3(a) of Senate Bill 709, 2011 Regular Session, if Senate Bill 709 becomes law. The result of these consolidated studies, if applicable, shall result in one final report from the Department.

SECTION 7. This act is effective when it becomes law.

In the General Assembly read three times and ratified this the 17th day of June, 2011.

s/ Walter H. Dalton
President of the Senate

s/ Thom Tillis
Speaker of the House of Representatives

s/ Beverly E. Perdue
Governor

Approved 5:16 p.m. this 23rd day of June, 2011