

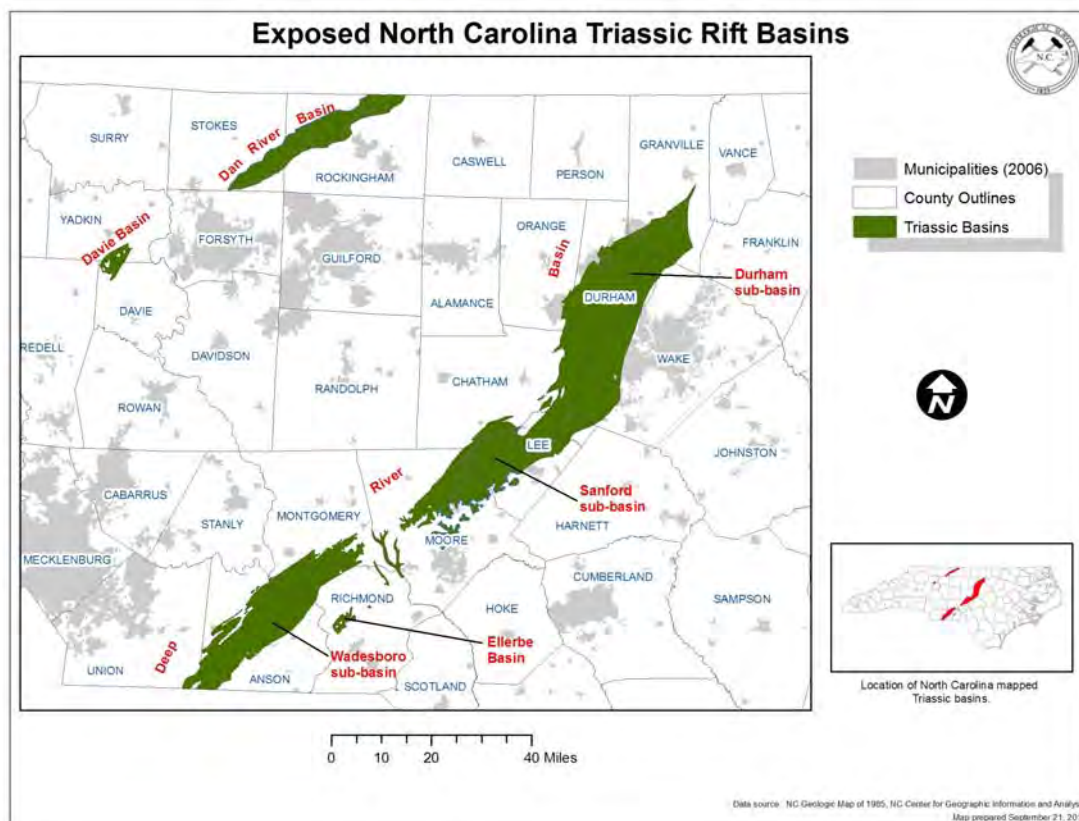
Section 1 – Potential Oil and Gas Resources

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.

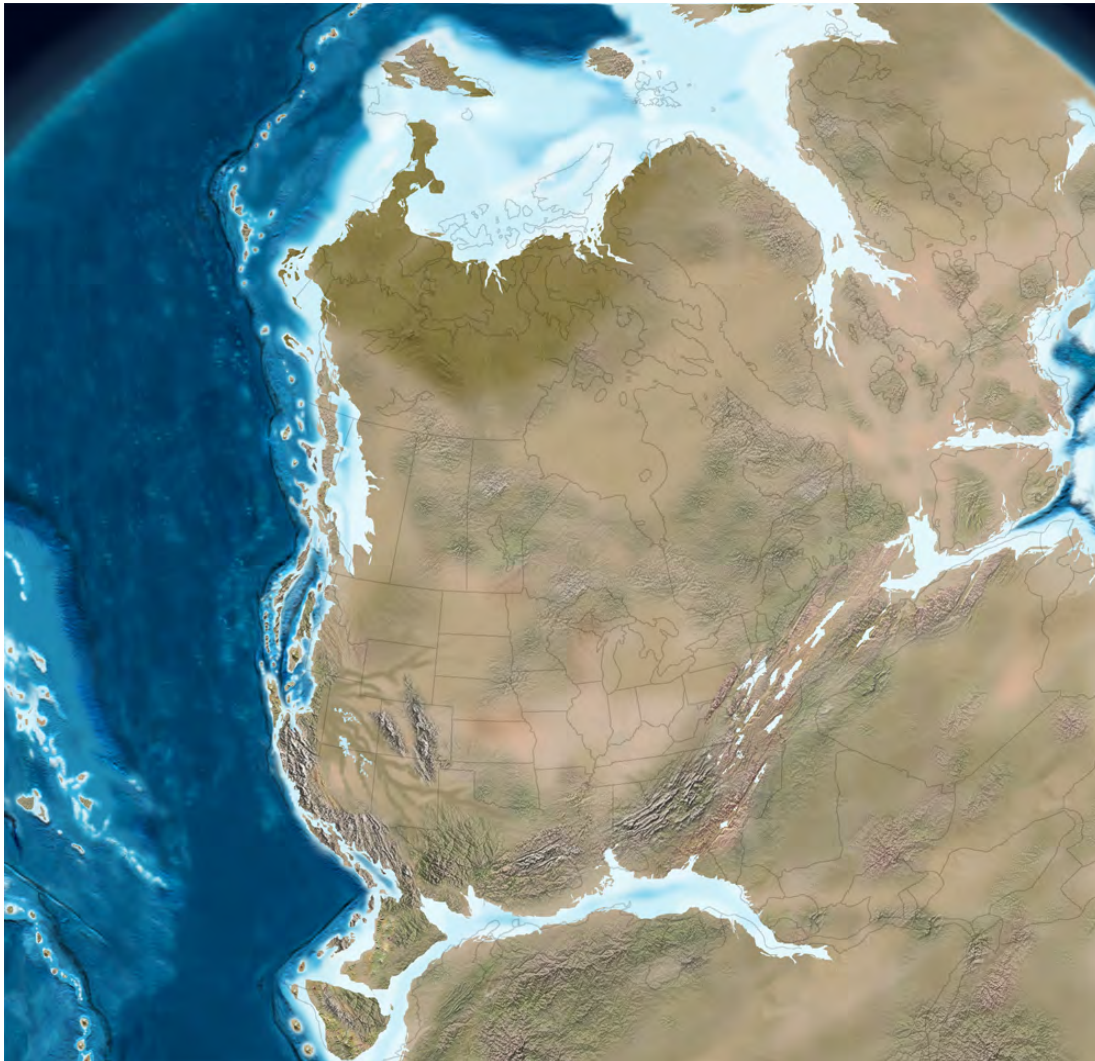
Figure 1-1. Exposed North Carolina Triassic Basins



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.

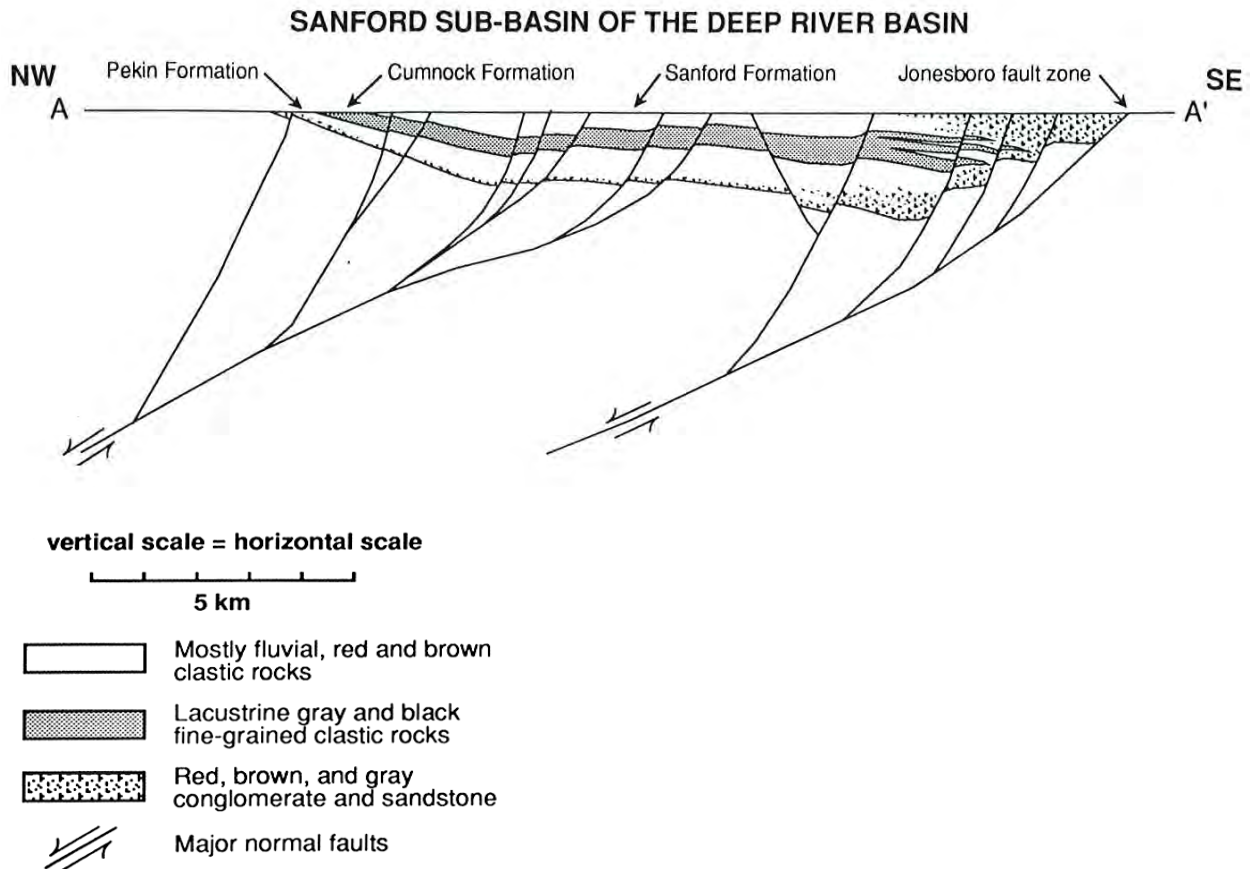
Figure 1-3. The Mesozoic Basins of the eastern United States. The city of Raleigh is shown for reference and the Sanford sub-basin in outline by a red box.



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.



Four of the eight oil and gas exploration wells drilled in the Sanford sub-basin are located along Seismic Section 113, which is parallel to the published cross-section in Figure 1-4. The depths from the surface to the top of the Cumnock formation for those four wells are: Butler #1 – 1,960 feet; Simpson #1 – 2,380 feet; V.R. Gross – 2,360 feet; and Bobby Hall – 4,190 feet.

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 2009-01³ 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

¹Reid, 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.

²North 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

³Reid, 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 Maturity⁵

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 Values⁶

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

⁴Jarvie, Dan. "Evaluation of Hydrocarbon Generation and Storage in the Barnett Shale, Ft. Worth Basin, Texas." Humble Instruments & Services, Inc. 2004. Accessed February 19, 2012.

<http://blumtexas.tripod.com/sitebuildercontent/sitebuilderfiles/humblebarnettshaleprespttc.pdf>

⁵Pennsylvania Department of Conservation and Natural Resources. "Thermal Maturation and Petroleum Generation." Accessed February 19, 2012.

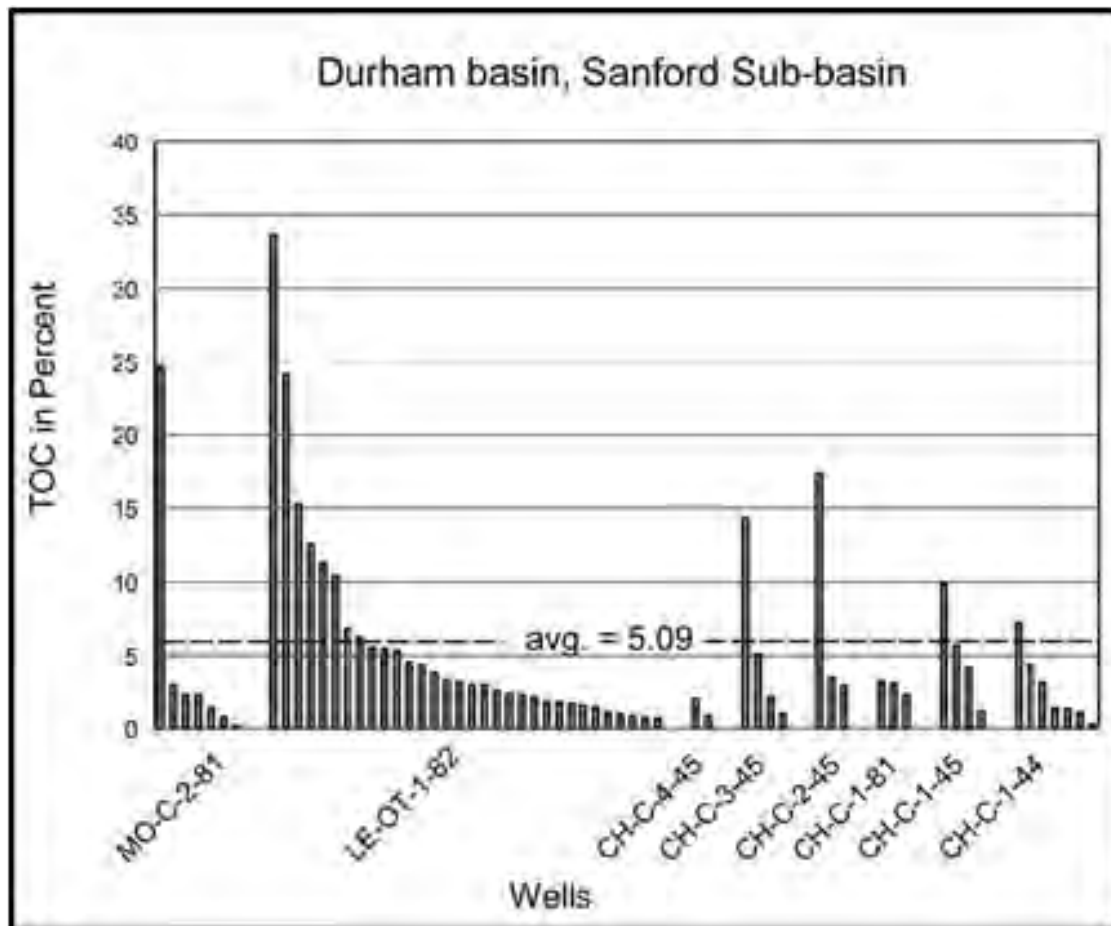
http://www.dcnr.state.pa.us/topogeo/oilandgas/sourcerock_maturation.aspx.

⁶Jarvie, 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).



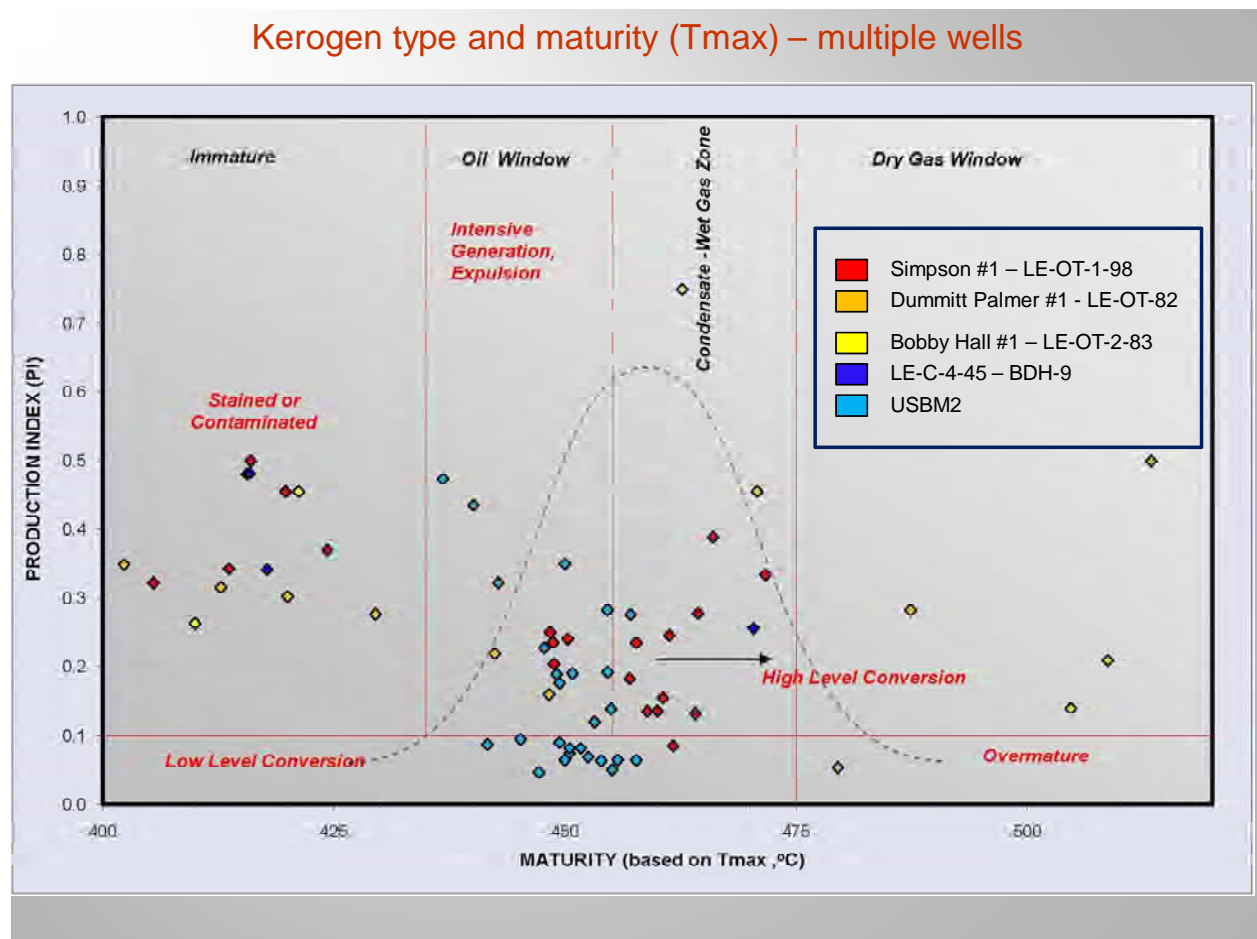
Geochemical laboratory tests also showed the organic matter is derived from terrestrial Type III woody (coaly) material and from lacustrine Type I (algal material), which is a preliminary indicator for wet gas (natural gas with light oil condensates). The quantity of potential gas volumes or the potential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

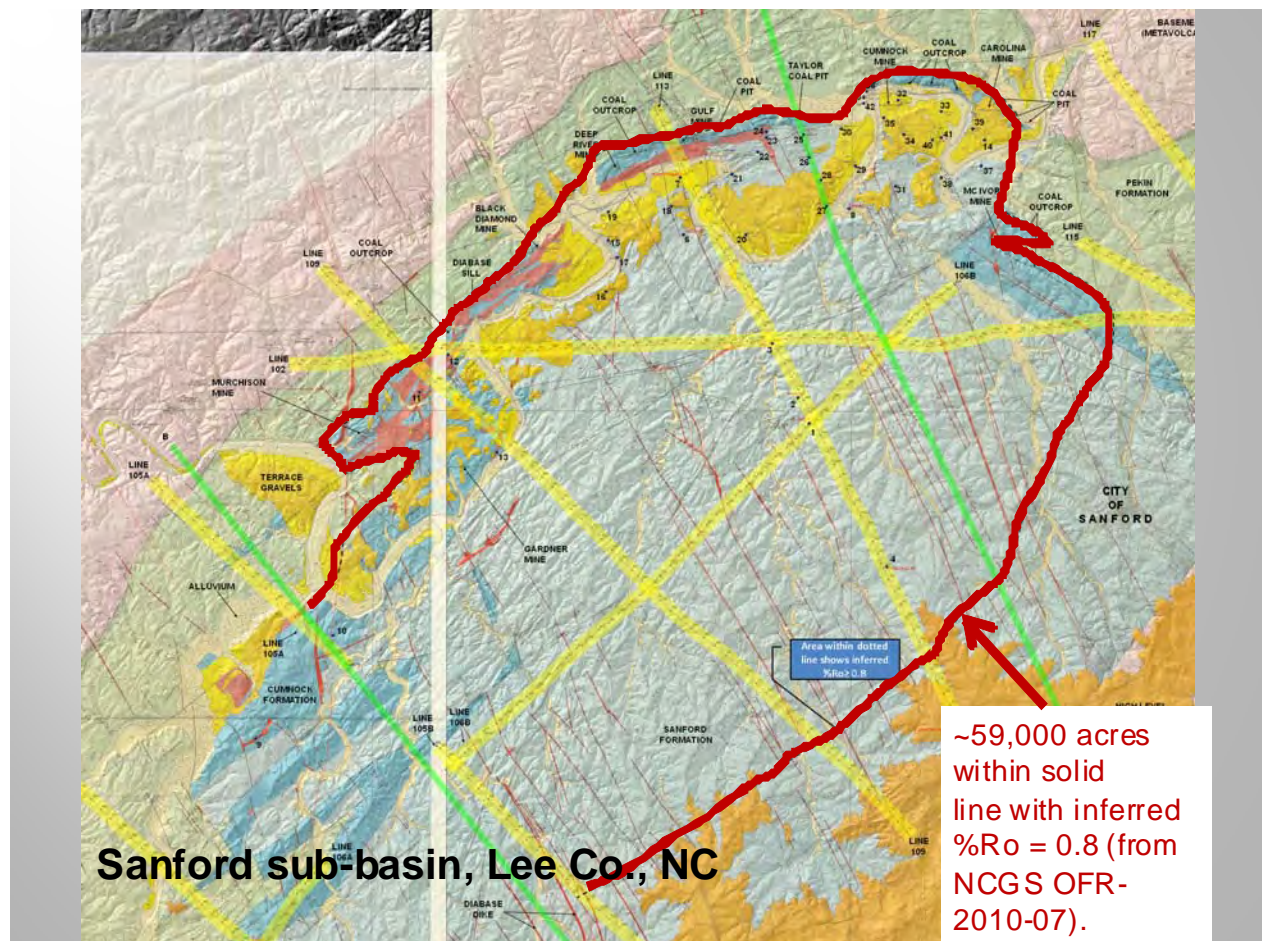


Combining the organic geochemical data with the interpretation of the 1985-86 seismic data delineated a potential target location with an area of more than 59,000 acres, which is shown in Figure 1-7. This compilation map shows the location of seismic lines, detailed geologic mapping from Reinemund (1947, 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 bodies (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).



In 1978 and 1979, the U.S. Army Corps of Engineers (USACE) contracted with N.C. State University and later with the University of North Carolina at Chapel Hill to investigate potential groundwater resources in the land adjacent to the future site of the Jordan Lake. During those investigations, the USACE was looking for groundwater resources in the diabase dikes to sustain potable water usage by campers at campsites around the lake.

The intrusion of the diabase dikes and sills at temperatures of 1,200 degrees Fahrenheit baked the country rock, which significantly reduced the country rock's permeability. As the diabase cooled, cracks formed inside the dikes and sills, which provided avenues for water to further

weather the diabase. This process provides the potential for a tabular body of groundwater to be held by the country rock like a cistern.

Using hand-held proton precession magnetometers, students from the two schools collected data from dozens of traverses to find and map the dike locations. Profiles across the dikes were analyzed to determine the dike orientation. Next, electrical resistivity profiles were collected to determine if there were indicators of groundwater in the weathered dikes.

For dikes with the lowest resistivity measurements, USACE contractors drilled test wells and conducted pump tests to assess potential groundwater resources. While both schools found groundwater in the diabase dikes, the resources were insufficient to support the proposed number of campsites. Today, dikes in the Triassic basins are sometimes a source of groundwater. The country rock within about half of the thickness of the dike or sill is altered by the intrusive heat and will become less permeable. Any oil and gas within those zones is destroyed. It is unclear at this time if natural gas exploration companies would see advantages in drilling near the diabase dikes and sills. While several peer-reviewed studies on gas migration in Pennsylvania have been published on the migration of thermogenic methane from deep sources such as the Marcellus and the Utica shales, current data for northeastern Pennsylvania shows the thermogenic methane is sources from the upper Devonian Catskill Formation, not the deeper sources.⁸ Three-dimensional seismic reflection data, some collected using three-component geophones, would provide the best indicator of the presence of dikes, sills and faults. This information would assist the state by providing a better understanding of the structure of the Triassic rocks.

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).

⁸ Molofsky, Lisa J, J.A. Connor, S. K. Farhat, A.S. Wylie, Jr., T. Wagner (2011). Methane in Pennsylvania water wells unrelated to Marcellus shale fracturing , Oil and Gas Journal (December 5, 2011 edition), 12 pp.

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).

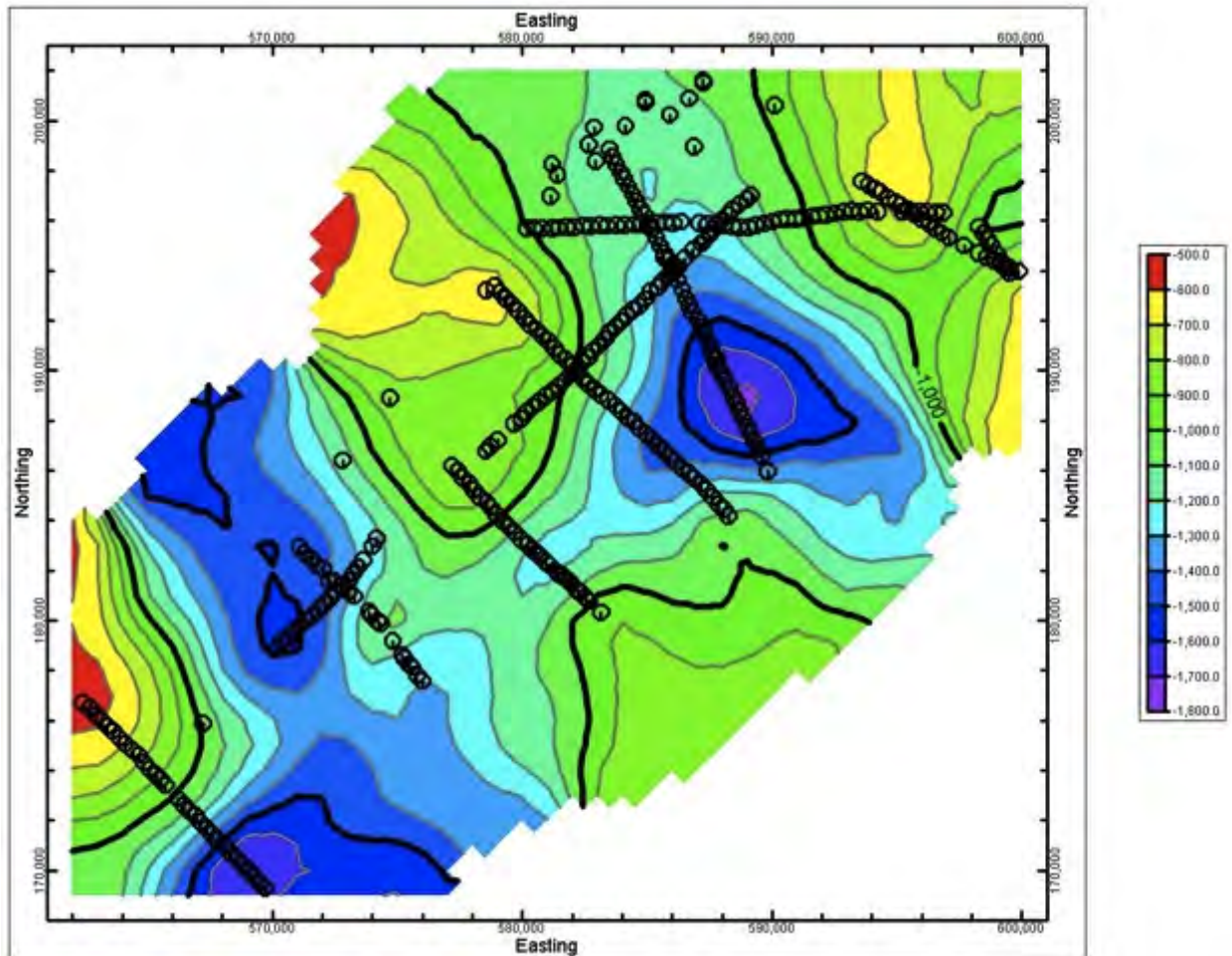
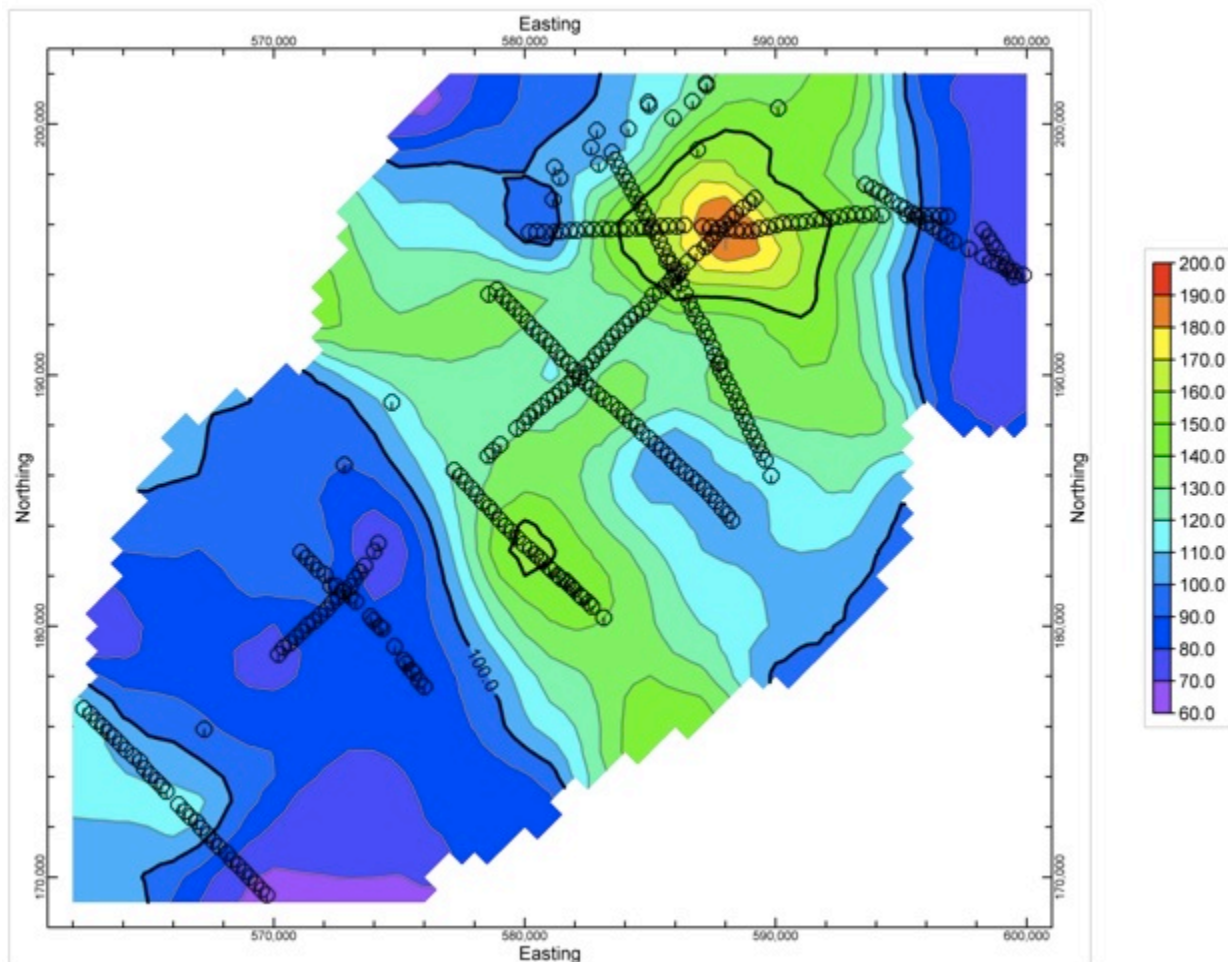


Figure 1-9. Map of the thickness of the organic-rich shale (Cumnock Formation) in the Sanford sub-basin. The units are in meters and the average thickness ranges from 60 meters (~180 feet) to 180 meters (~540 feet).



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 thought to be recoverable using potentially available 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.⁹

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.

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

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.

⁹Email by Brenda Pierce, USGS to James Simons, January 31, 2012.

As noted above, the term “original gas-in-place” refers to the entire volume of gas in the reservoir, regardless of the ability to produce it. The term “technically recoverable gas” refers to the total amount of the resource, both discovered and undiscovered, that is thought to be recoverable with potentially available technology, regardless of economics. For purposes of the economic assessment, DENR estimated the total amount of gas per well for two wells, or original gas-in-place, and has recommended using 20 percent of any estimate of original gas-in-place as an estimate of the amount of gas that could actually be produced (technically recoverable gas).

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 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 840×10^6 cfg. Both the estimate of original gas-in-place 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.

In examining the resource potential for shale gas, which is an unconventional or continuous resource, the variables used in an analysis are (1) the source unit thickness, (2) extent of the resources in acres and (3) the volume of standard cubic feet of gas per cubic foot of source rock. From the beginning, the area in which the N.C. Geological Survey had collected the most information was the Sanford sub-basin. This information was drawn from two wells: Simpson #1 and Butler #3, both drilled in 1998. A petrophysical report was given to the state by the exploration company as part of the data sharing requirements of the North Carolina Oil and Gas Conservation Act.

The values from that report were the thickness of the tested interval and the volume of gas estimated for a hypothetical well draining 160 acres (one quarter of a square mile). For Simpson #1, the interval was 150.8 feet, which produced 1,225 million cubic feet of gas. The interval in feet was multiplied by the area of 160 acres (6.97 million square feet), which gave a volume of 1.05 billion cubic feet. The ratio of the volume of gas to the volume of rock was 1.17 cfg/cfr (cubic feet of gas per cubic foot of source rock).

For Butler #3, the interval was 11.9 feet, which produced 405 million cubic feet of gas. The interval was multiplied by an area of 160 acres and gave a rock volume of 82.9 million cubic feet. The ratio of the volume of gas to the volume of rock was 4.88 cfg/cfr. The mean of these two values was 3.02 with a standard deviation of 2.62.

For the determination of an average total recoverable gas volume, a unit thickness of 200 feet was used. The thickness map of for the Cumnock Formation averages 500 feet with a maximum of 800 feet in measured sections. Again, multiplying the area of 160 acres in square feet with the unit thickness gives a total area of rock which is then multiplied by the previously determined ratio of cubic feet of gas / cubic feet of rock. The result of this calculation gave 4.2 billion cubic feet of gas for the average well with a drainage area of 160 acres.

To determine the estimate of technically recoverable gas, one multiplies the volume of original gas-in-place by a 20 percent recovery rate. This results in 840 million cubic feet of gas for an average well. With 59,000 acres identified as prospective, and a well spacing of 160 acres, there would be 368 wells.

Subject to the limitations noted above, DENR has used this data to estimate the volume of technically recoverable gas 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.¹⁰ At 160-acre spacing, 368 wells could potentially be drilled in the Sanford sub-basin, for a volume of technically recoverable gas of 309 Bcfg for the 59,000-acre area. These estimates of both total number of wells and volume of technically recoverable gas have been used as a reference point in other parts of the study.

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 and 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 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, a new period of leasing began with the first leases 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.

¹⁰ 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.

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 March 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.¹¹ 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.

¹¹ 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.

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.

Drilling is not the first activity to occur once a large lease block is secured. First, two-dimensional or three-dimensional seismic reflection data will be collected at target areas. Seismic data is proprietary, and existing law in North Carolina does not require companies to share that information with the State. Although seismic data was collected in the Sanford sub-basin in 1985, personnel in the N.C. Geological Survey did not see that data until more than 15 years later, and only then because a company volunteered to share that information with the state.