# 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.

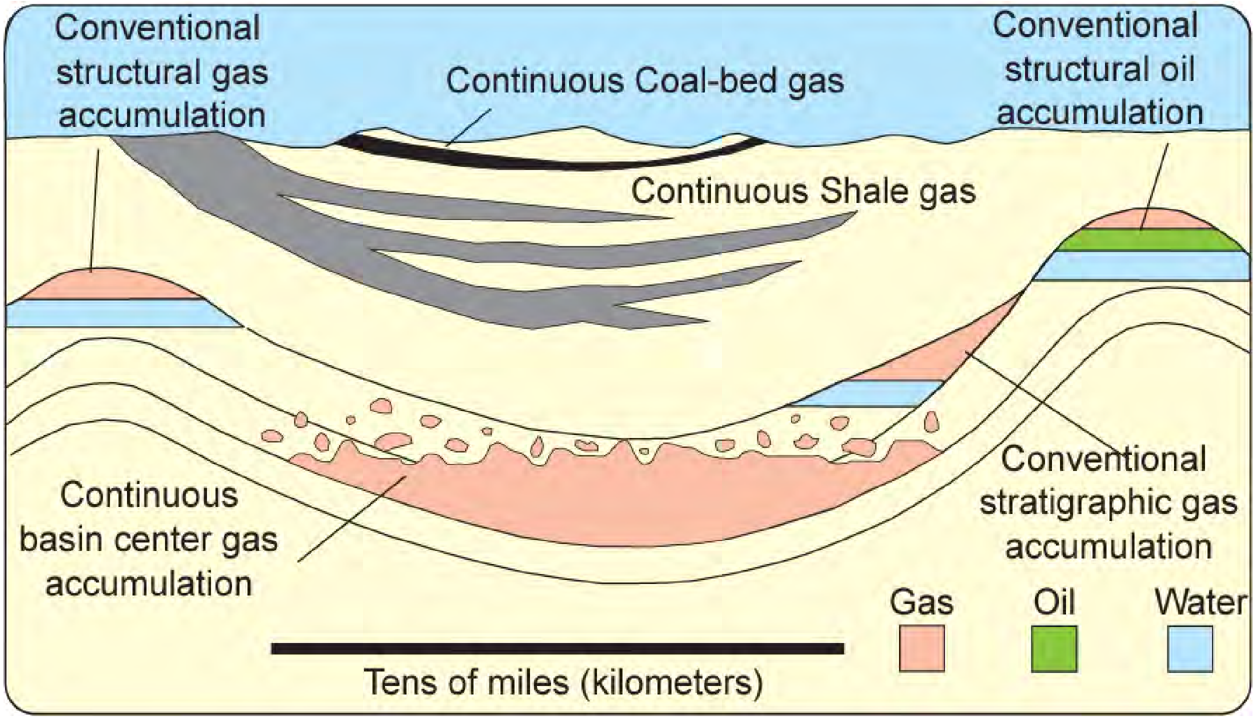
The generation of hydrocarbons starts with the organic-rich sediments. Organic matter contains kerogen, a naturally occurring solid that is insoluble in organic solvents (which means that it cannot be extracted from them). There are three types of kerogen (Types I to III). Type I is formed mainly from 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,[12] 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.[13] 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 $1/1000^{th}$ 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

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

[13] 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.**

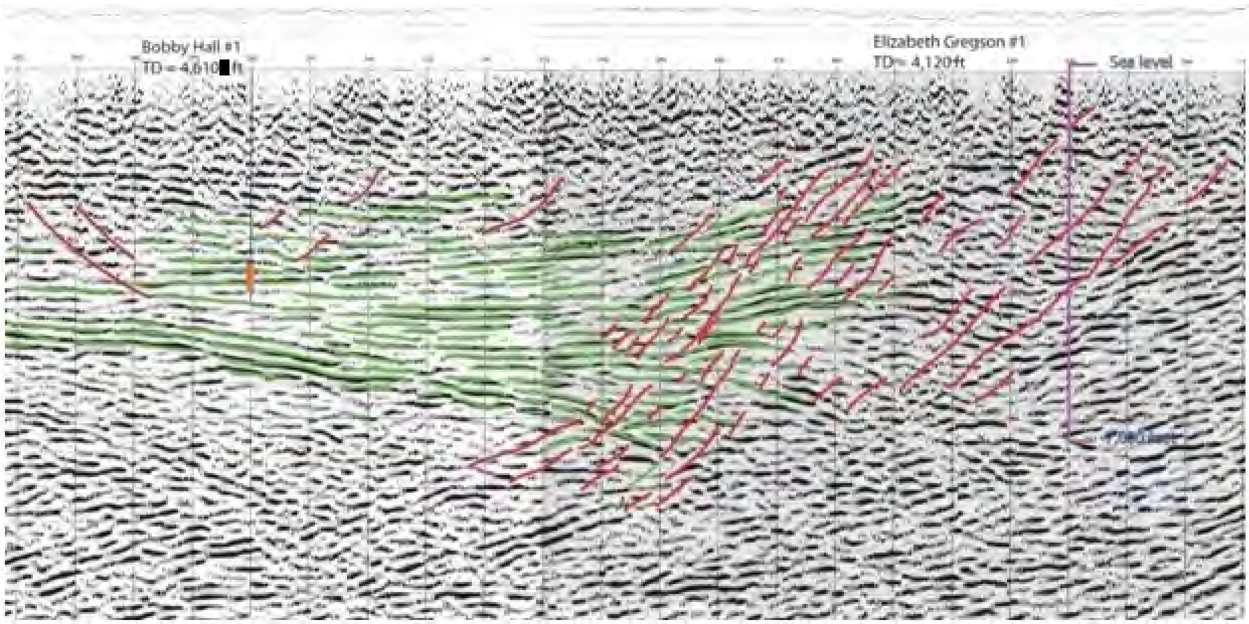
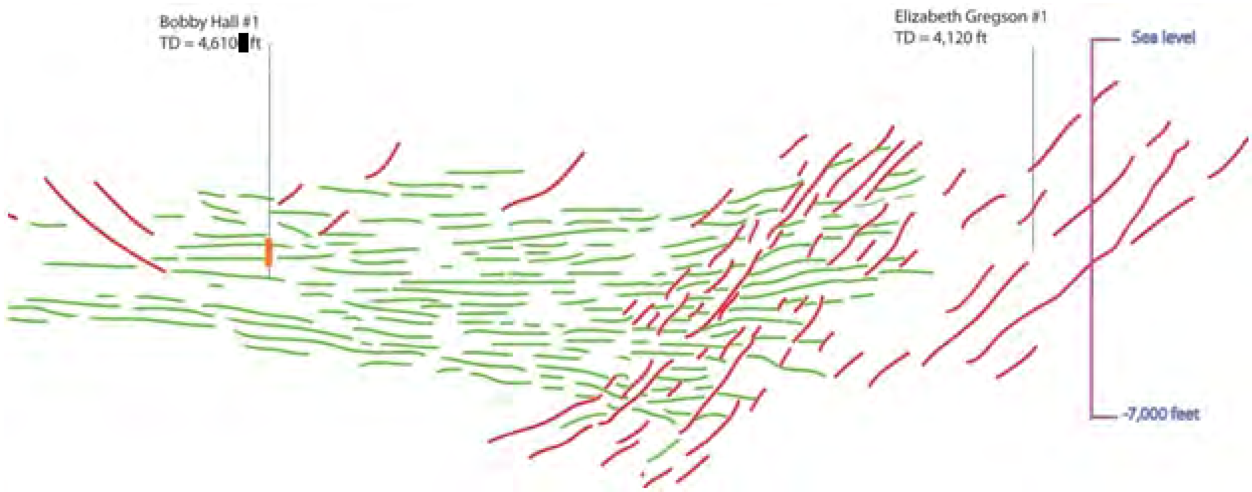


**Figure 2-3. Interpretation of Seismic Reflection Line 113 across the Sanford sub-basin, Deep River Basin. The interpreted reflectors are highlighted in green and the offsets on the reflectors are shown in red and are interpreted to show the location of faults at depth. The purple line shows the estimated 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 matured 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. [14] 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 bond 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

[14] 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.

In Arkansas, the field rules make a drilling unit one square mile (640 acres). This is convenient for that state since the land is divided by township and range grid. The mile square has a 560-foot buffer on all four sides, which results in only 397 acres drilled in each 640 acre block. The rules further state that there are 16 wells in that interior block of 4,160 feet by 4,160 feet. The horizontal laterals are parallel to each other and are 520 feet apart. In this example, there are 16 wells in 640 acres, which equals a 40-acre well spacing, but one must recall only 62 percent of the drilling block will be drilled due to the 560-foot buffer. At 397 acres divided by 16 wells, the spacing is 24.8 acres per well and the recovery rate is close to 30 percent.

**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.[15]

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:

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[15] 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/.

> "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..." [16]

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

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

carry the chemical and sand proppant.[17] 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 wells in Texas, Pennsylvania, Colorado, Oklahoma and New Mexico.[18] 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] 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.
[18] 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.