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Shale Gas Development in the United States

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1. Introduction

Although natural gas has been obtained from organic-rich shales in the United States since the first commercial gas well was produced in 1821 to provide gas light to four commercial establishments and a mill in the small town of Fredonia, New York, large-scale shale gas production is a recent phenomenon. Assessments of the geological and engineering challenges of shale gas resources were performed in the 1970s and 1980s, as new domestic energy sources were sought in response to an oil embargo imposed upon the United States, and the resulting "energy crisis" that followed. The amount of natural gas present in the shales was found to be significant, but commercial production had to await advances in drilling and completion technology that came about in the 1990s. The new technology allowed for the economic development of this resource in the 21st Century.

1.1 Basic shale geology

Shale is the name for a class of sedimentary rocks. The term shale refers to a rock that is composed primarily of tiny grains of clay minerals and quartz, the mineral components of mud. These materials were deposited as sediment in water, which was then buried, compacted by the weight of overlying sediment, and cemented together to form a rock through a process called lithification. Clay minerals are a type of sheet silicate related to mica that usually occurs in the form of thin plates or flakes. As the sediment was deposited, the flakes of clay tended to stack together flat, one on top of another like a deck of cards, and as a result, lithified shale often has the property of splitting into paper-thin sheets. This is called fissility, and it is an easy way to identify shale from other fine-grained rocks like limestone or siltstone.

Because the grains of material that make up shale are so small, pore spaces between these grains are equally small. Although shale can have porosity in the range of ten percent, the pores and flowpaths are so tiny that it is difficult for any fluids in the pores, like gas, oil or water, to flow out of the rock. Cracks or fractures are needed to for flowpaths.

Shale comes in two general varieties based on organic content: dark or light. Dark colored or black shales are organic-rich, whereas the lighter colored shales are organic-lean. Organic-rich shales were deposited under conditions of little or no oxygen in the water, which preserved the organic material from decay. The organic matter was mostly plant debris that had accumulated with the sediment. As these materials were buried deeply beneath

younger sediments and subjected to intense heat and pressure over geologic time periods, they became hydrocarbons, or what we know as oil, gas and coal.

A location with a good exposure of rock that is representative of the formation as a whole is called the "type section," and formation names are assigned by geologists after a nearby geographic feature. Some well-known gas shales in the United States include the Marcellus Shale, named for the village of Marcellus, New York (figure 1), and the Barnett Shale, named for exposures in the valley of a creek called the Barnett Stream near Fort Worth, Texas (Stamm, 2011).

Fig. 1. Marcellus Shale type section near Marcellus, New York, showing natural fractures. Rock hammer is 13 inches (33 cm) in length, tip pointed north. Photo by D.J. Soeder.

1.2 Natural gas in shale

Shale gas resources are huge. Estimates tabulated by Bruner and Smosna (2011) from different authors on the size of the Marcellus Shale resource alone range from about 85 trillion cubic feet (TCF) to nearly 500 TCF of technically recoverable gas. (One TCF equals about 9.3 billion cubic meters). The Utica Shale below the Marcellus may have even greater reserves. Such numbers are of course built on many assumptions about the geology, gas generating potential, gas in place, and percentage of recoverable gas, resulting in a wide range of estimates. In nearly all cases, however, they are quite large when compared to conventional gas reservoirs. The amount of gas consumed annually in the United States is about 23 TCF, making the "hundreds" of TCF considered recoverable from domestic gas shales a significant resource, no matter what the exact figure might be.

To understand why the gas resources in these shale formations are so large, it is helpful to review the manner in which oil and gas are created over geologic time periods. Rocks that have the ability to produce hydrocarbons in commercial quantities with standard well drilling technology are known as conventional reservoirs. The hydrocarbons present in a conventional reservoir were usually created elsewhere, and migrated into the porous and permeable reservoir rock, where they were trapped. Creating a conventional oil and gas reservoir is a complicated process that requires a number of events to occur in a specific order. These are: 1) source rock, 2) thermal maturity, 3) reservoir rock, 4) trap and seal, and 5) migration pathway. The rarity of all these things happening with precise timing and in the proper sequence is the main reason oil and gas can often be quite difficult to find.

Source rock: Petroleum and natural gas were formed from decayed plant matter trapped and preserved in fine-grained sediments. Two common sources of organic material were algae or other water plants, and woody land plants. Some animals may have contributed as well, but most fossil fuel is derived from ancient plant material, not dead dinosaurs. Decay bacteria usually require oxygen, so if the dead plants settled to the bottom in water that contained low levels of dissolved oxygen, the organic matter was often preserved and buried under more sediment. These organic-rich sediments (later turned into rock) are known as source rocks. Until recently, source rocks were not considered to be much good for production, because they are generally made up of fine-grained, low permeability materials deposited in quiet water environments, like black shale.

Thermal maturity: In addition to containing a few percent of preserved organic matter, the source rock sediment had to be buried deeply, and subjected to heat and pressure within the Earth to become thermally mature. Temperatures within the Earth increase with depth. This is called the geothermal gradient and varies with location. In most places, the temperature generally increases by about 25 degrees C with every kilometer of depth (Blackwell and Richards, 2004). More deeply buried rocks were exposed to higher temperatures. Organic materials, exposed to high temperatures over geologic time periods slowly break down without oxidizing, turning organic carbohydrates into fossil fuel hydrocarbons such as coal, oil and natural gas.

The thermal maturity of a gas shale is related to its burial history. For example, Lash (2008) published an analysis for Devonian formations in western New York, determining that the Marcellus Shale was initially buried rapidly beneath a thick wedge of sediments, then uplifted and eroded by mountain-building before being buried again under more sediment derived from the new mountains. Parts of the Marcellus Shale that were deeply buried were exposed to temperatures above 175 degrees C for millions of years, thoroughly cooking everything in the rock. Most measurements of thermal maturity on the Marcellus Shale place it quite high, well beyond the liquid petroleum range. Dry methane gas is almost the only hydrocarbon remaining in this shale, although some ethane is present in the western part of the basin.

Other shales with lower thermal maturity ranges do produce liquids along with the gas. A shale in Texas called the Eagle Ford produces dry methane gas where it is deeply buried, and significant natural gas liquids in shallower areas. Natural gas liquids are known as condensate, which travels up the well as a vapor, but then condenses into liquid form under the lower pressures and temperatures at the surface. Condensates such as propane and butane are worth substantial money, and are eagerly sought by the petroleum industry.

Reservoir rock: Conventional oil and gas production comes from reservoir rocks, which consist of coarse-grained sandstones or limestones with significant porosity and high permeability. These formations are too open and sponge-like to be good source rocks, but if a source rock elsewhere is able to fill up the reservoir rock pore spaces with oil and gas, it is easy to produce with conventional wells.

Trap and seal: In order to contain the gas and oil in a conventional reservoir rock, there must be some kind of a trap, such as a fold or a fault, to create an underground structure that acts as container of sorts to hold the hydrocarbons in the reservoir rock. To be effective, the trap must also include an impermeable caprock to seal the reservoir and contain the hydrocarbons within.

Migration pathway: Because the source rocks and reservoir rocks are usually completely different formations, once the oil and gas have formed in the source rock, they need a migration path to get from the source rock to a reservoir rock. This can be a fracture like a fault that allows movement through the intervening rocks, or just tilted beds that will let hydrocarbons slowly flow updip. Timing is everything: if the migration pathway is in place before a reservoir rock is available, the oil and gas will be lost. On the other hand, if the reservoir rock is present but no migration path ever develops, the reservoir stays empty.

In summary, a driller will end up with a dry hole in a conventional oil or gas reservoir if any one of the five items described above is missing, or occurs out of sequence.

Gas shales are unconventional reservoirs. This means that they are significantly larger than a conventional reservoir, but they are also much more difficult to produce. The shale acts as both the source rock and the reservoir rock. The gas in the shale was created from organic material deposited with the sediment, and was not required to migrate anywhere to be trapped in a reservoir. However, because the gas has remained in the shale, it must be produced directly from this fine-grained, impermeable rock, and that is not a simple task.

If the quality of most natural resources is plotted against the quantity, a triangle or pyramid shape is typically produced, showing a small amount of high-quality resource, and significantly larger volumes as the quality goes down (figure 2). The lower quality resource is usually more difficult and expensive to produce, but if there is a technological or economic breakthrough that makes it competitive with the higher-graded resource, the production quantities can be enormous. This has happened with commodities like iron, coal, gold, and timber, to name a few. For example, high purity drinking water from protected springs or pristine mountain streams is in very limited supply. However, suppose a new technology allowed seawater to be turned into drinking water of the same quality at a similar cost, or better yet, cheaper. Supplies would suddenly expand greatly.

This is essentially what happened with shale gas. The application of new drilling and hydraulic fracturing technology has allowed drillers to extract this gas directly from the source rock at prices comparable to gas from conventional reservoirs.

The U.S. Geological Survey (USGS) has the responsibility for estimating oil and gas resources in the United States, including shale gas. USGS hydrocarbon assessments are based on mathematical models, which use an understanding of the geology of the rock unit and the production characteristics of existing wells. The production data used by the USGS

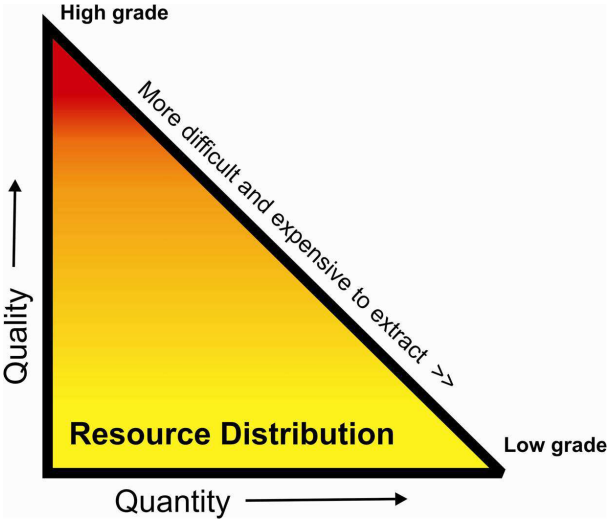


Fig. 2. The resource triangle illustrating the distribution of most natural resources, including natural gas, when quantity is plotted against quality.

are the decline curves, or the fall-off in production over time, from a large number of gas wells. Unfortunately, very little decline curve data have been made available, and production from gas shales is so new that most of the wells have not declined very much anyway. As such, calculations of the true size of the shale gas resource have been problematic at best (Coleman and others, 2011).

The wide range of estimates for U.S. domestic shale gas resources is a clear sign that a better understanding is needed of the processes that generate and store gas in the shale. Greater rigor may also need to be applied to some of the assumptions used in the various estimates. Discovering how the physical properties of the shale act to control the limits of gas content would help to constrain the numbers and provide more accurate and realistic estimates of gas in place, or GIP.

The amount of recoverable gas is always a fraction of the GIP, under the assumption that 100 percent of the gas will never be recovered, even under the best of circumstances. Hydraulic fractures don't contact every part of the formation, some pores may be blocked with water or oil, and others may not be connected to flowpaths. The value for this fraction varies from assessment to assessment, ranging from a low of about 10 percent up to 50 percent or even higher. In one of the classic publications on the resource, Engelder and Lash (2008) stated that the Marcellus Shale GIP exceeds 500 TCF over an area encompassing parts of New York, Pennsylvania, West Virginia, and Ohio. They assumed a technically recoverable gas fraction of 10%, leading to a reserve estimate of 50 TCF. This caused quite a stir at the time, because 50 TCF of producible gas from a single formation was more than double the annual consumption of natural gas in the entire United States.

It has only gone up from there. More refined calculations by Engelder (2009) came up with significantly higher estimates for GIP, and a 50 percent probability that the Marcellus Shale will ultimately yield 489 TCF of gas, assuming a power-law decline rate, 80-acre well

spacing, and 50 year well life. U.S. government numbers for Marcellus Shale recoverable gas from the U.S. Energy Information Administration (EIA) are about 410 TCF (EIA, 2011). A recent Marcellus Shale assessment by the USGS (Coleman, 2011) has concluded that the median amount of technically recoverable gas from this formation is about 84 TCF, and it may go as high as 144 TCF, but this is still quite conservative compared to some of the other numbers out there. The EIA recently reduced their estimates to be more in line with the high end numbers from the USGS.

Why is there so much gas in shales like the Marcellus? Most geologists agree that the gas was derived from rich deposits of organic matter in the shale, formed from abundant marine algae that grew and died in a shallow inland sea during the time of Marcellus Shale deposition. Wrightstone (2011) suggests that the planktonic or floating marine plants were fertilized by mineral-laden dust blown into the basin by trade winds off arid highland areas to the east. Periodic dust storms from these deserts would have added fine particles of quartz to the water in the enclosed basin, along with a host of mineral nutrients, including iron and phosphorous. It has been known for some time that iron is an essential fertilizer for algae. The dust-blown minerals could have fertilized an explosion of plant growth in the water. Wrightstone cites documentation from a modern algae bloom that occurred in the Tasman Sea after an Australian dust storm of epic proportions in 2009, and similar blooms in the Atlantic Ocean from dust storms off the Sahara Desert. Under a microscope, a significant part of the mineral matter in the Marcellus Shale can be seen to be composed of small particles of quartz that are just the right size to have been carried by the wind.

Algal blooms concentrate a great deal of organic matter in the water column, and then transport this organic matter to the ocean bottom when the plants die and sink. When these blooms happen, bacteria trying to feed on large masses of dead algae rapidly remove any residual oxygen from the bottom waters and create anoxic sediments, which preserve the organic material. The anoxic muds were then buried, exposed to heat and pressure, and generated copious amounts of methane gas.

2. History of U.S. shale gas investigations

Although the first commercial American gas well was hand-dug into Devonian-age shale in Fredonia, NY by William Hart in 1821, serious shale gas studies did not begin in the United States until the 1970s, in response to oil shortages that led to an "energy crisis." This crisis was actually a series of oil shocks precipitated by a Middle East war in 1973, and the Iranian revolution in 1979. The energy shortages experienced during these episodes worried the American public, and influenced U.S. foreign policy.

The Middle East war known variously among historians as the Yom Kippur War, the Ramadan War, the 1973 Arab-Israeli War, or the Fourth Arab-Israeli War was fought between October 6 and October 25, 1973. Lasting less than a month, it involved armies from Egypt, Syria, Iraq and Jordan attacking Israel, followed by an Israeli counterattack, and ended with a U.N. brokered ceasefire (Rabinovich, 2004). Both the United States and Soviet Union enlisted the two sides as proxies, with the Soviets resupplying and supporting Egypt, and the Americans airlifting material and providing intelligence support to Israel. U.S. involvement led some members of the Organization of Petroleum Exporting Countries, an oil cartel better known by its acronym OPEC, to call for an embargo on oil exports to the United States. At a meeting of oil ministers in Kuwait on October 20, 1973, members of OPEC declared a total embargo on American oil deliveries (Yergin, 1991).

The oil embargo on the U.S. lasted until the spring of 1974. Although this was at a time when significantly less than half of the oil used in the United States was imported, and not all the member countries of OPEC had even joined in the embargo, the action still resulted in severe shortages, long lines at gasoline stations when there was fuel available, and consumer panic. The price of oil quadrupled almost overnight. The American driving public, who had not worried about gasoline supplies since the days of fuel rationing during the Second World War, were shocked and stunned.

The U.S. postwar housing boom had relocated many people into suburbs at long distances from city centers. Suburban life meant that automobiles were required for nearly all transportation needs. Fuel shortages and price hikes in the winter of 1973-74 raised the prospect of being stuck with an empty gas tank in a useless car, and unable to carry out the simplest tasks. In the rhetoric of the time, people demanded that something be done to prevent America from being held "hostage" to imported oil. Many people thought that if the United States could send men to the moon, we ought to be able to figure out how to fuel our automobiles. The public outcry forced the government to act. The United States Department of Energy (DOE) was formed from a number of smaller agencies as a cabinet-level entity of the U.S. federal government under President Jimmy Carter on August 4, 1977. Along with inherited responsibilities like running the national labs and maintaining the nation's nuclear weapons stockpile, a primary mission of the new DOE was to find technological solutions to the energy crisis.

The second oil shock hit in 1979, during the Iranian revolution. The student protests that eventually led to the fall of the Shah severely disrupted Iranian oil production, and essentially curtailed exports for several months. Although the United States received only a relatively small percentage of imported oil from Iran, the disruption to global supplies was enough to precipitate a second oil shortage, with the same gasoline station lines and panic as seen in 1973. The 1979 crisis was much shorter-lived, however, because Saudi Arabia and other exporting nations were able to make up for the Iranian oil shortages and return American imports to nearly steady levels (Yergin, 1991).

Schrider and Wise (1980) described some of the potential new domestic sources of fossil fuel, including natural gas, being investigated by DOE. These included unconventional gas resources such as coalbed methane, tight gas sands, gas dissolved in deep brines under high pressures, and shale gas. There was no doubt that the production of these would be a technical challenge, but if they could be exploited, the energy would help displace imported oil. A number of scientific and engineering investigations were begun on unconventional energy resources by the U.S. government, one of which was the Eastern Gas Shales Project.

2.1 U.S. Department of Energy Eastern Gas Shales Project

In 1975, the Energy Research and Development Administration, a predecessor agency to the U.S. Department of Energy, initiated the Eastern Gas Shales Project (EGSP) to assess the potential for a sequence of Devonian-age shales in the Appalachian Basin, as well as similar rock units in the Michigan and Illinois Basins to produce large amounts of natural gas under the proper conditions. The initial definition of proper conditions was to find organic-rich black shales that contained abundant natural fractures. The organic matter in the black shales would provide the gas, and the fractures would provide the flowpaths. Engineering

experiments would seek to link the natural fractures through a series of man-made hydraulic fractures, creating a network of high-permeability flowpaths through the shales.

Under DOE, the EGSP had 3 major components: resource characterization, development of production technology, and the transfer of that technology to industry. The project was managed by the DOE Morgantown Energy Technology Center (METC) in West Virginia, which later became a campus of the present-day DOE National Energy Technology Laboratory (NETL). Over a period of about 6 years, from 1976 to 1982, the EGSP used cooperative agreements with drillers to collect oriented drill core from a variety of shale units in the Appalachian, Michigan and Illinois Basins. Directional or "oriented" core was necessary, because one of the major pieces of data being gathered was the strike and dip of the natural fractures. Most of the EGSP cores came out of the Appalachian Basin, and many of these were from the shallower, western side near the Ohio River. The shale sequence in the eastern part of the basin is considerably deeper, and therefore more expensive to drill. Only eight of the EGSP wells were drilled all the way down to the Marcellus Shale, and data from those are now in high demand.

Cores were collected from 34 different EGSP wells in the Appalachian Basin, in formations ranging from the Cleveland Shale to the Marcellus Shale. Three wells were also cored in the Devonian Antrim Shale of the Michigan Basin, and seven wells into the equivalent New Albany Shale in the Illinois Basin, for a total of 44. The locations of the EGSP wells in the Appalachian Basin are shown in figure 3 (Bolyard, 1981).

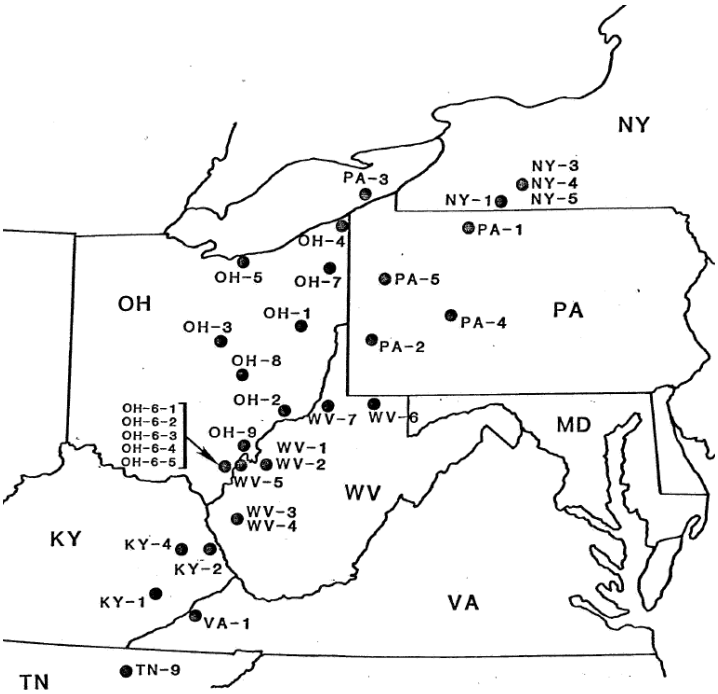


Fig. 3. Map locations of the DOE Eastern Gas Shales Project drill cores collected in the Appalachian Basin between 1975 and 1981. Figure from Bolyard, 1981.

As soon as the core was recovered, it was unloaded from the plastic sleeves used to line the core barrel, washed to remove drilling mud, assembled, aligned, measured for length and had depths marked on it. The cores were solid cylinders of rock, 3.5 inches (9 cm) in diameter that weighed about ten pounds per foot (~15 kg per meter). The field crew then set to work collecting and preserving samples, and creating a field description of the lithology, noting in particular any gas shows, natural fractures or other features. The most time-sensitive of the field samples were short segments of core designated for chemical gas analysis. As quickly as possible, but certainly within two hours of the core reaching the surface, these offgassing samples were hermetically sealed in steel cans. The cans were sent to a chemistry lab in Ohio, where the composition of the gas was analyzed as it came out of the rock. The final field task was to pack the core back up into the plastic liners and cap the ends for transport to the EGSP core lab in Morgantown, WV.

Once the core arrived at the lab, it was laid out on tables, carefully pieced together, cleaned, oriented and measured. Using the core orientation data and a circular plastic protractor, north lines were drawn on the rock cylinders in permanent marker, which allowed for the measurement of the orientation of any features or natural fractures encountered in the core (figure 4).

Fig. 4. Black Cleveland Shale above gray Chagrin Shale in an EGSP core from Ohio, with pyrite at the contact (2040.54 ft.). An orientation groove is visible to the right of the depth marks; the vertical line on the front of the core marks north. Photo by Daniel J. Soeder.

Cores were then processed for data collection. The lithology and color of the core were described from bottom to top. Wet core surfaces were compared to standardized color chips to determine color. Many so-called black shales are actually a yellowish black color similar in tint to ripe olives. Only the Marcellus Shale was found to be a true charcoal black. Correlations between organic carbon content, gas potential and "blackness" of the shale were impractical, because once the organic carbon content reached a few percent, the shale was black and didn't get any blacker with more carbon (Hosterman and Whitlow, 1980).

Fractures were identified as natural or coring-induced, based on criteria defined by Kulander and others (1977). Natural fractures were further classified as joints or faults. Joints are fractures where the two walls have simply pulled apart. Faults are fractures where the two walls have slid past each other; often leaving a polished, grooved surface behind called a slickenside. The orientation of the natural fractures was measured using the north directional line on the cores as a reference. The frequency of the coring- induced fractures was counted, but little else could be done with them. It was hoped that they could at least provide an indication of the brittleness of the rock, and a possible response to hydraulic fracturing. Rock samples were collected from the cores for the various labs, agencies and universities that had asked for them, and small wooden blocks were inserted into the core to mark where each sample was taken from, and who had it.

The cores were photographed with a specially made rig that could trundle a camera down the length of a core table. The photos were hand-pasted into albums and kept as a reference. Sadly, many of these photos suffered water damage years later when in storage, and have been lost. Gamma radiation readings were collected on the cores every foot (30 cm) using a scintillometer for comparison with gamma ray logs collected downhole on a wireline tool. Unfortunately, like the core photographs, the scintillometer readings have also been lost over the three decades that have passed since the data were first collected.

Funding for the Eastern Gas Shales Project formally ended in 1992, but the budget had been at relatively low levels since 1982. Despite the low funding levels, a number of cutting edge engineering experiments were run on shale. An air-drilled, horizontal test well was completed in the Huron Shale in December 1986 (Duda and others, 1991), which was drilled with the intent of intercepting existing fractures and improving the efficiency of natural gas recovery. Innovative logging techniques, directional drilling techniques, assessments of reservoir anisotropy, liquid CO2 fracturing, and other new technologies were tried out on gas shales during the last decade of the program. These studies greatly assisted industry in the commercial development of shale gas a decade later.

By 2007, many of the old EGSP reports, publications and data tables were being eagerly sought out by industry people interested in the potential of shale gas, and personnel at DOE-NETL started getting numerous requests for copies. Many of these had been packed away for years, or were quite rare. In response to increasing demands for information as unconventional gas drilling expanded, the NETL library assembled nearly every relevant document from the DOE unconventional gas program, some of which were literally down to the last copy in the known universe. The documents were transferred into an electronic format and placed on two DVDs, allowing hundreds of reports and scientific papers on western U.S. gas sands, secondary gas recovery, eastern U.S. gas shales, methane hydrates, deep source gas, and methane recovery from coalbeds to be carried in one's pocket.

There were many other aspects of the Eastern Gas Shales Project above and beyond the core recovery and analysis activity, but that part of the work is described here because it would later turn out to be an important factor in the decision to develop the Marcellus Shale gas resource. Many of the other EGSP efforts, including drilling engineering and well design, field tests on a wide variety of reservoir stimulation techniques, early attempts at computer modeling, development of an assessment procedure and nomenclature for rock fractures, a vast amount of gas chemistry and geochemistry analysis, and geological basin studies were equally pioneering in the development of shale gas and other unconventional gas resources.

2.2 Institute of Gas Technology shale gas research

The Institute of Gas Technology (IGT), located in Chicago, Illinois is now known as the Gas Technology Institute (GTI). It had been founded in 1949 as a research institute for the gas utility companies, who were moving away from the use of manufactured or town gas, made from coal and water, and replacing it with natural gas from oil wells that was being pipelined up from the Gulf Coast. Town gas was extremely hazardous, consisting of a mixture of carbon monoxide and hydrogen. Natural gas, on the other hand, is composed of non-toxic methane, and it was abundant in the oilfields of Texas and Louisiana. Interstate transmission companies were building thousand-mile pipelines from production areas on the Gulf Coast to market areas in the Northeast and Midwest. In order to recoup some of the costs of the pipelines and new distribution systems, the gas utility and transmission companies wanted to encourage the use of more natural gas. IGT was initially founded to conduct gas utilization research, developing new consumer appliances, and finding additional commercial and industrial applications for natural gas. It wasn't until the first energy crisis in 1973 that IGT began a natural gas supply research program.

In the early 1980s, IGT had a subcontract with Sandia National Lab to analyze the core from a DOE tight gas sand project called the Multiwell Experiment, or MWX. Tight gas sand is a sandstone formation with reasonable porosity and a fair amount of gas in the pores, but with permeability almost as low as that of a shale. It is an abundant gas resource in a number of southern and western states in the U.S., and in western Canada. The challenge is figuring out how to extract the gas economically. The MWX was a series of three wells drilled relatively close together into the Mesaverde Formation in the Piceance Basin of western Colorado. One of the wells was hydraulically fractured, and the other two were observed for effects. The final part of the experiment was to drill an angled borehole across the hydraulic fracture, and capture it in the core, which was done successfully.

The analysis of rock properties such as porosity, permeability, capillary entry pressure, pore volume compressibility, pore size distribution and flowpath width are collectively known as petrophysics. IGT developed a laboratory instrument to accurately measure the petrophysical properties of tight sandstone core samples under pressure conditions representative of the rocks at depth. The key was to maintain stable air temperatures inside the apparatus, so gas pressures would not fluctuate due to thermal changes. Under these steady temperatures, volume and flow measurements using gas were very accurate. The apparatus employed a reference pressure stable to about one part in half a million, and it could accurately measure gas flows lower than one millionth of a standard cubic centimeter (gas at room temperature and atmospheric pressure) per second. This is equivalent to a cubic centimeter of gas flowing from a rock over a time period of a million seconds, which is

more than 11 ½ days. The reason for making this point is that the device was also used to measure gas flow through shale. Some people have questioned whether such low flow measurements could actually be made with this degree of precision, and the answer is yes. The flows were measured with electronic sensors, and the apparatus was controlled by a 1980s version of a desktop computer, which in those days used cassette tapes to transfer programs and record data. The device was named the Computer-Operated Rock Analysis Lab or CORAL. It was described in detail at a Society of Petroleum Engineers (SPE) meeting, and in a paper by Randolph (1983).

When the subcontract with Sandia National Lab expired, IGT received funding in 1983 directly from DOE to do additional core analysis and experimental work with the CORAL, including trying to measure simultaneous gas and water flow through tight sandstone cores. IGT suggested that the CORAL could also be used to try collecting some gas permeability data on EGSP shale core, because such permeability data were not in the literature. The DOE project manager agreed, and supplied IGT with a list of "zones of interest" in many of the original EGSP cores based on gas production or gas shows, correlation with gas-productive intervals in nearby wells, successful stimulation results, and indications of high organic content.

At the end of active core collection in 1982, the EGSP core lab had been shut down, and the shale cores were shipped to the state geological surveys in the state where they had been cut for storage and safekeeping. Twenty-eight zones of interest were sampled by IGT from thirteen cores in Ohio, Kentucky, New York, Pennsylvania and West Virginia.

In the end, IGT was only able to run two full loads of shale core in the CORAL. The device had four core holders, so this was a total of eight samples in all. Six of the samples were black Huron Shale, a member of the Ohio Shale, which was known to be gas productive in southwestern WV. One of the Huron Shale cores in the first batch had cracked in the coreholder, so core seven was a repeat run of another sample from this same well. Core number eight was a Marcellus Shale sample from the EGSP WV-6 well.

The CORAL had been upgraded in anticipation of the shale analyses. The upgrades included changing the flow directions of the air circulation system so temperatures of critical components were more stable and returned to equilibrium more quickly, improving the digitizing resolution with a better data logger, and rewriting the temperature control software so it could predict when temperatures were nearing a setpoint and reduce power to the heating coils beforehand, instead of overshooting and then having to correct. These changes, driven by the desire to make measurements on shale, led to an overall improvement in the performance of the apparatus and provided better data on all samples.

Small rock cylinders cut from the EGSP core samples for CORAL analysis were dried in a controlled relative humidity oven to remove water from the rock without dehydrating the clays. Proper drying under controlled relative humidity was important for obtaining useful measurements (Soeder, 1986). Harsh drying, under high temperatures and/or in a vacuum oven causes clay minerals to dry out and collapse, opening up pores and creating abnormal permeability. Samples dried at 60°C under 45% relative humidity retain a layer of bound water on clays and other hydrated minerals, although free water in the pores is removed. Many analyses on a variety of tight sandstones and other rocks had confirmed this.

IGT core analysis on the eight samples of EGSP shale revealed a number of important findings (Soeder, 1988). The first was that the Huron Shale samples contained small but

significant amounts of petroleum in the pores, which blocked gas flow. Under low differential pressures, no measureable gas flowed through these cores at all. At high differential pressure, gas flow rates gradually increased over a period of hours before leveling out. The data appeared to show that a liquid phase was being pushed out of the pore system by the gas pressure, and gas permeability was slowly increasing as the flowpaths were cleared of liquid. Dozens of tight sandstone measurements made on samples dried under the same temperature and relative humidity conditions had never shown any evidence of a liquid water phase in the samples. Yet all of the Huron Shale cores showed some kind of liquid draining from the pores under pressure. The IGT analytical chemistry lab placed a sample of the Huron Shale core in a tagged solvent and ran the liquid through a gas chromatograph. The data revealed that the Huron Shale contained a light paraffinic petroleum, typical of Appalachian Basin oils. It is important to note that a similar analysis on the Marcellus Shale sample revealed that there was no oil present in this rock.

The discovery of oil blocking the pores of the Huron Shale helped explain some of the erratic results of the earlier EGSP reservoir stimulation experiments. Many different types of stimulations had been used, including hydraulic fracturing, explosives, and fracturing with cryogenic liquids, gas and foam, among others. The results had been hit or miss at best – some stimulation methods performed well on certain formations in certain locations, and poorly elsewhere. There were not enough data to explain why this should be, and a 1982 report concluded that reservoir stimulation alone was insufficient to achieve commercial shale gas production (Horton, 1982). This conclusion implied that the situation was a bit more complicated than the old EGSP idea that any black shale will produce gas if sufficiently fractured. With the finding that oil was blocking gas flow in the pores of at least some shales, a few of the stimulation failures became more understandable.

The Marcellus Shale sample was measured by IGT in August 1984. Gas flowed through this sample with remarkable ease, and excellent data were collected. The values for gas permeability (reported as $K\infty$) were 19.6 μd (microdarcies) at 3000 psi net confining pressure, and about 6 μd at 6000 psi net confining pressure (Soeder, 1988). The high sensitivity of permeability to net confining stress (i.e. doubling the net stress reduced permeability by more than two thirds) has implications with respect to production drawdown and the expected economics of shale gas wells. Loss of flow under higher net stress will be offset somewhat by increased gas slippage as pore pressures are lowered during production. Shale gas has not been produced long enough for many wells to have entered these stress and pressure regimes, but this is certainly a concern for the future. Obviously, a lot more data are needed to understand the petrophysics of shale.

The CORAL apparatus at IGT was also capable of measuring the pore volume of a core sample under representative net confining stress using a Boyle's Law (pressure-volume equivalence) technique. The device used a volume-calibrated, positive displacement pump, and a sensitive differential pressure transducer to measure pore volumes with an accuracy of 0.01 cm^3. Porosity of the Marcellus Shale core was measured using nitrogen gas at two pressures to check the validity of the data points. Instead of obtaining the same value for pore volume regardless of pressure, significantly more nitrogen gas went into the sample at lower pressure. This higher apparent porosity at low pressure is a sign that some of the gas was being adsorbed. The phenomenon of adsorption occurs when gas molecules attach themselves to electrostatic surfaces inside the pores. The nitrogen data prompted another,

more thorough gas porosity measurement at a wider range of pressures using methane, the main component of natural gas. These data showed that the amount of methane the Marcellus Shale could hold was equal to 0.224 times the square root of the pressure. This is called an isotherm in adsorption chemistry and defines an adsorption function. When these data are plotted on a linear graph to show the volume of methane per volume of rock as a function of pressure, the curve shown in figure 5 emerges. The curved line is due to adsorption; if this was strictly a pressure-volume relationship, the line would be ruler-straight. When this curve is extended out to the value of 3500 psi reported for the initial gas pressure of the Marcellus Shale in the EGSP WV-6 well, where the core originated, the calculation shows a gas-in-place value for this shale of approximately 26.5 standard cubic feet of gas (scf) per cubic foot (ft^3) of rock. This was an important piece of data, because the National Petroleum Council (1980) had assessed the gas potential of Appalachian Basin shales at just 0.1 to 0.6 scf/ft^3. The IGT value of 26.5 scf/ft^3 in the Marcellus Shale core from EGSP WV-6 was an astounding 44 to 265 times greater than the NPC estimate. No one had ever reported this much gas in a black shale before. The results were published in a DOE report, and as an SPE journal article (Soeder, 1988).

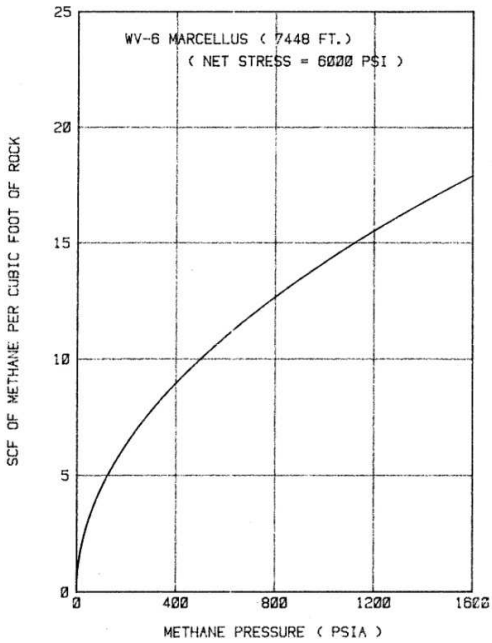


Fig. 5. Natural gas potential in the Marcellus Shale from methane porosity data measured as a function of pressure. From Soeder (1988).

3. Production of shale gas

The people bewildered by all the drill rigs setting up across the Pennsylvania countryside might be surprised to learn that the Marcellus Shale drilling did not simply come as a bolt from the blue. After the end of the Eastern Gas Shales Project, the drilling industry

continued to innovate with the development of new drilling technology and new hydraulic fracturing techniques. The potential applications of these new techniques to the production of shale gas were carefully scrutinized by George P. Mitchell, the co-founder of Mitchell Energy, who had been involved with shale gas since the early days of the EGSP, drilling a number of cooperative wells with DOE in Ohio. Mitchell was interested in the gas potential of the Barnett Shale in Texas. Like the Marcellus and other shales, it was difficult to obtain economical amounts of gas from vertical wells in the Barnett. Mitchell Energy tried a lot of different drilling techniques and reservoir stimulation methods over a period of about 18 years, including massive hydraulic fracture stimulations, which did produce significant flows of gas, but at very high cost.

The key to producing economical quantities of shale gas has turned out to be the ability to drill and fracture horizontal boreholes through the rock, which contacts much more formation volume than a vertical well. The typical black shale thickness of only a few hundred feet (tens of meters) limits the amount of contact a single vertical well can have with the rock. Drilling horizontally, however, allows the wellbore to remain within the shale, and penetrate distances of thousands of feet (kilometers). The drilling is coupled with hydraulic fracturing to create high permeability flowpaths into the shale. Instead of the single hydrofracs done in vertical wells, the long horizontal boreholes allow for an entire series of hydraulic fractures to be spaced a few hundred feet apart (figure 6). There can be ten or more of these so-called "staged" hydrofracs in a horizontal borehole, resulting in large volumes of gas production. Drilling costs for a horizontal Marcellus well are approximately 2-3 times higher than for a vertical well, but the initial gas production can be 3-4 times greater (Engelder and Lash, 2008).

Advances in horizontal drilling, or more accurately, directional drilling, came about in the 1990s, driven by the needs of deepwater offshore oil production. As offshore rigs moved into deeper water, the engineering design of the platforms changed. Steel towers standing on the sea bed had worked fine in shallower water, but drilling in thousands of feet of water required the use of semi-submerged, floating platforms held firmly in place by tensioned steel cables anchored into the seafloor. These platforms and their associated seabed anchor facilities were expensive and complicated to rig up. The less frequently they needed to be moved, the better.

Directional drilling was the answer. If a driller could bore a well directionally into one reservoir pocket, and then drill another well in a different direction from the same location to intercept a second reservoir pocket, a great deal of oil could be recovered without having to move the rig. This need and the large sums of money behind it drove the development of directional drilling forward in the 1990s. Some deepwater platforms now routinely drill as many as 60 separate directional wells from a single location.

Directional drilling had been around for years, but there were two problems with it that needed to be overcome: steering the bit and knowing where it was located. The first technological advance in directional drilling was the downhole motor. Without the need to turn the entire drill string from the surface, the drill pipe is much more flexible and can turn relatively tight corners. The modern design uses hydraulic power, supplied by a slurry of drilling mud pumped down the drill string under high pressure and through an impeller on the downhole motor. The motor then turns the bit, which cuts the rock. The impeller, motor

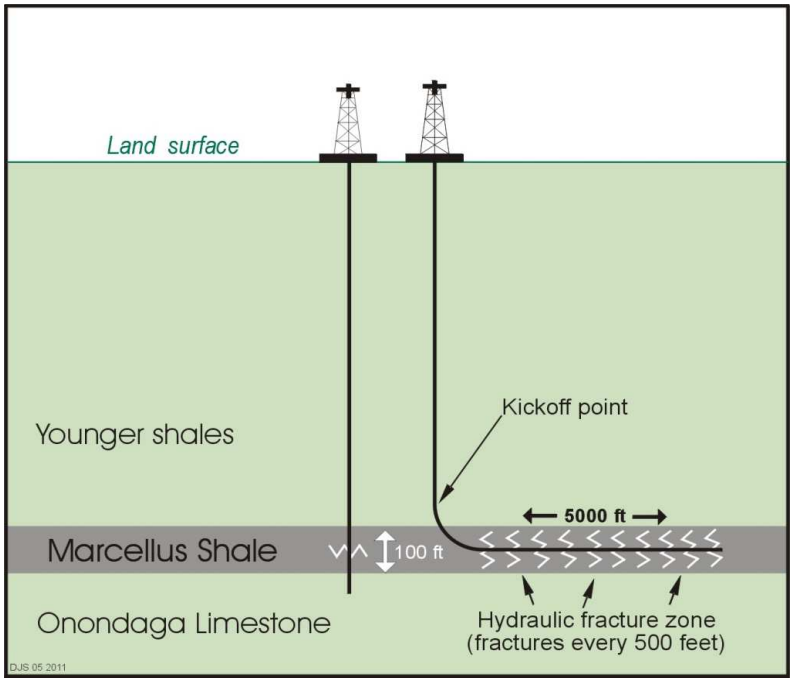


Fig. 6. Illustration of the combination of horizontal drilling and hydraulic fracturing technology used for shale gas. Not to scale. (Modified from Soeder and Kappel, 2009).

and bit together are known as the "bottomhole assembly," and it allows wells to be drilled in virtually any direction, including horizontally. The drill bit is steered by using a bent section of pipe near the bottomhole assembly to deviate the well away from vertical, by changing the pressure being applied against the cutting face, or by varying the rotational speed. Some advanced bits have thrust bearings controlled from the surface that change the angle of the cutting head to provide precise control.

Advances in downhole position measurement using a combination of inertial navigation with a gyroscopic compass and remote telemetry now allow drillers to more accurately monitor the downhole location of their drill bit and the configuration of the borehole. Data transmission methods vary, but usually involve digitally encoding the data and transmitting it to the surface as pressure pulses in the mud.

The depth at which a directional wellbore changes from vertical to some other orientation is called the kickoff point. The location in 3-dimensional space where the borehole is supposed to intercept the producing formation is called the target. The radius of the curve used to change the borehole direction from vertical to horizontal is called the build or the build rate. The horizontal stretch of the borehole is called the lateral. The path of the lateral through the target formation is called the trajectory.

Directional drilling in gas shale is laid out in patterns that look like the legs of a spider on a map. The body of the spider is the drill pad. Multiple wells will originate from a single drill pad, ranging from 6 to 10 or more in number. All of the wells start out vertical, and then

from a kickoff point about 500 feet (150 m) above the target, build a curve. The trajectory takes them down into the target shale in a direction that is usually perpendicular to the trend of the most prominent natural fractures, or joints. Laterals can extend 5,000 feet (1.5 km) or more in length, and are often drilled parallel to one another at some optimal spacing for the most efficient recovery of natural gas from the formation.

Because of the need to protect aquifers, the finished boreholes are lined with casing, held in place by cement. Casing is made of heavy steel pipe, which screws together in approximately 30-foot (10 m) segments. Each length of casing that is made up of joined segments of a particular diameter is known as a string. There are several concentric strings of casing in a well, with each successive casing string being smaller in diameter and extending to a greater depth. As each string of casing is placed in the hole, cement is pumped down through the center, and is distributed by a shoe at the bottom of the string so that it oozes up into the annular space between the casing and the borehole wall. Enough cement is pumped in to completely fill this annular space, and then left to cure. A proper cement job is critical for sealing the casing and keeping it in place.

Different casing configurations are used in different climates, but in the Appalachian Basin of North America, the following design is typical: The conductor casing is installed from the surface to a depth of 30 to 60 feet (10-20 m) as a mechanical barrier to support the sides of the hole in unconsolidated soil. This is the largest diameter string of casing used in a gas well, usually about 24 inches (60 cm) in diameter. Inside the conductor casing, a second, narrower casing string known as the surface casing (sometimes called the water or coal casing) is run and cemented in place from the surface down to a depth of several hundred feet below the deepest freshwater. The surface casing is 14 to 20 inches (35-50 cm) in diameter and is used to isolate the gas well from the aquifers and coal seams. It is designed to protect the groundwater by preventing any gas or oil from entering the aquifer, while at the same time keeping groundwater from flooding the well. Regulations for fresh groundwater protection tend to be conservative, and may require surface casing to be set as deep as a thousand feet (300 m).

From the bottom of the surface casing, the main vertical, curved and lateral portions of the borehole are drilled. Another string of casing, called the intermediate casing, is installed through this part of the hole down to the kick-off point of the curved borehole, and cemented into place. This casing is 9 to 12 inches (23-30 cm) in diameter, and its purpose is to keep the borehole walls from collapsing and to prevent any gas and liquid in the rocks above the target formation from entering the annular space of the well. A final string of well casing, called the production casing, is installed in the finished hole. It is usually only about 5 inches (13 cm) in diameter, and extends from the surface down the vertical hole, through the curve and along the entire length of the lateral to the very bottom end or toe of the hole. It is cemented into place through the production zone to the base of the intermediate casing, and serves to channel all gas production directly to the surface, without any opportunities to go astray.

The completion process for the well begins by punching holes in a section of the lateral casing in the production zone using shaped explosive charges on a wireline carrier. This perforation of the casing creates contact with the reservoir. The holes and cement behind the casing are cleaned using a 15% solution of hydrochloric acid. The hydraulic fracturing process begins by pressure testing and calibrating all of the equipment. Water, chemicals and sand are mixed in a blender and pumped downhole. As the hydrofrac begins, the pump rate is brought up slowly

while pressures at the wellhead, downhole, and in the annulus behind the production casing are carefully monitored. The frac fluid is pressurized until the breakdown pressure of the formation is exceeded and the rock cracks open. The initial part of the frac is just water, called the pad. It is followed by water mixed with sand pumped in as a proppant, to keep the fractures open after pressure is released. A flow meter on the blender measures the volume of fluid pumped downhole, and a densometer measures the amount of sand in the fluid. Engineers watch the wellhead, annulus and bottomhole pressures, pump rate, fluid density and material parameters throughout the frac. When the first stage of hydraulic fracturing is finished, the pressure is released and a seal called a bridge plug is set into the production casing to close off the perforated and fractured interval from the rest of the well. The hydraulic fracture treatment is repeated in a second stage, which is then also closed off with another bridge plug. The process continues until the last stage reaches the upper end of the lateral, called the heel, and begins to curve up out of the shale.

After all the stages of fracturing have been completed, the bridge plugs are removed. Gas pressure in the rocks is used to push the frac fluid out of the well during a procedure called "blowback," which is designed to remove as much of the liquid as possible. The expelled fluid is diverted into a holding tank. Because the well is not yet on production, this operation requires that the gas be burned-off or flared. The water being pushed out of the well by gas pressure is called flowback fluid, and the flow of liquid can persist intermittently for weeks. Once the gas production begins after the initial discharge of flowback fluid, a production wellhead is installed along with a gas meter and connector line, and the gas is sold to a transmission company. Most operators filter and recycle the flowback fluid into the next frac to avoid the costs of disposal.

3.1 Development of shale gas resources

George Mitchell truly believed in the gas potential of the Barnett Shale, and would not give up. Because of his determination, Mitchell Energy continued their field experiments in Texas, eventually developing something called a light sand frac, which was more effective on the shale at a lower cost than most other hydraulic fracture treatments. A rise in gas prices in the mid-1990s improved the economics. By 1997, Mitchell had perfected the light sand frac technique in vertical wells, and started trying it in horizontal wells. They began successfully producing commercial amounts of gas from the Barnett Shale using horizontal boreholes and staged hydrofracturing in the early 21st century.

In the summer of 2004, Southwestern Energy announced that the Fayetteville Shale in Arkansas had many of the same characteristics that made the Barnett Shale gas productive, which set off another gas drilling boom. Oil and gas producers familiar with the Barnett Shale rushed to northern Arkansas to get in on the Fayetteville Shale. Similar drilling booms followed soon afterward on the Haynesville Shale in the Arkansas-Louisiana-Texas border region known as the ArkLaTex, and the Marcellus Shale in Pennsylvania.

The Marcellus Shale was developed in the southwestern corner of Pennsylvania by a company called Range Resources, who remain a major producer in the area. In 2005, Range was drilling a vertical well called Rentz#1 in Washington County, PA to test oil and gas prospects in the Lockport Dolomite. This is a Silurian carbonate rock in the Appalachian Basin, older than the Marcellus Shale and located below it. The Lockport was originally deposited as a calcite-rich limestone, which was later altered into a different rock called

dolomite (named after the Italian mountains where it is common) by magnesium-enriched groundwater. The alteration process causes calcium carbonate (calcite) to recrystallize into a magnesium/calcium carbonate mineral also called dolomite (the rock is often referred to as "dolostone" to distinguish it from the mineral). The mineral dolomite usually forms larger crystals than calcite, giving a sugary texture to the formerly fine-grained limestone, which creates porosity that may contain oil and gas. There is no guarantee that hydrocarbons will be present, however. A mantra of all oil and gas geologists is that despite all the geology and geophysics used for exploration, you never really know what's down there until you get down there, and the only way to get down there is to drill.

The Rentz well came back with poor gas shows from the target formation. Bill Zagorski, the Range Resources geologist in charge of the well, was left wondering what to do with this non-productive, dry hole. Zagorski found himself in Houston a few months later, trying to sell an interest in developing a shale gas prospect in Alabama using Mitchell Energy's production technology, when he recalled that he had seen evidence of gas in the Devonian shale section penetrated by the Rentz well above the Lockport Dolomite. Some of the historical data he had researched when selecting the well location reported gas shows and even a "blowout" in old drilling records, which he realized were at depths near the Marcellus Shale (Durham, 2010). Zagorski researched what was known about gas resources in the Marcellus Shale, which included finding many of the old DOE and SPE publications on the subject from the EGSP work two decades earlier, and got the go-ahead from his company to try a completion in the Marcellus.

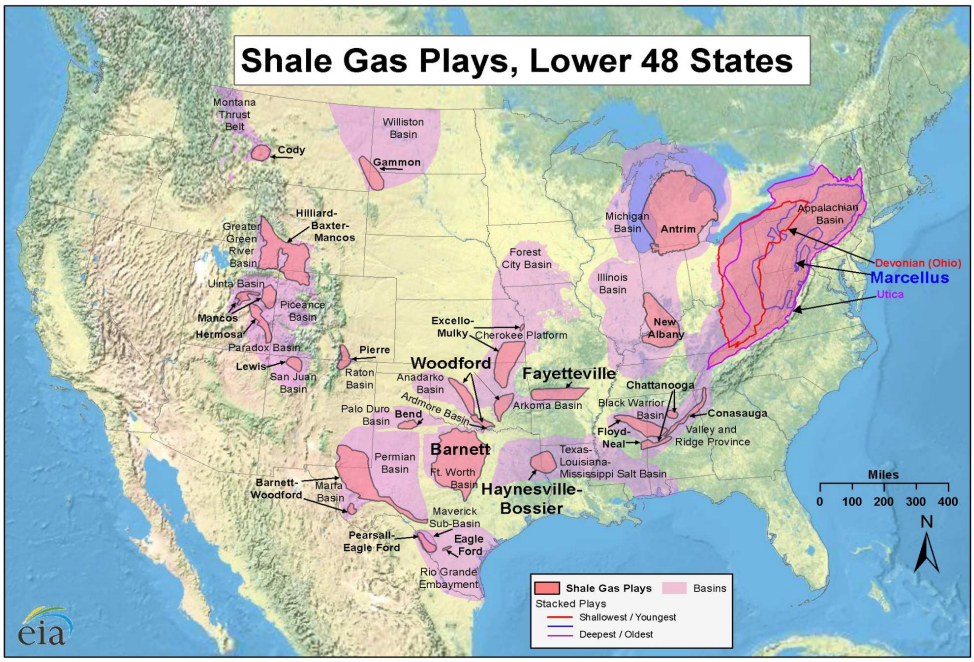
Range Resources re-completed the vertical Rentz#1 well in the Marcellus Shale, and got a significant return of initial gas production. Thus encouraged, they drilled the first few horizontal Marcellus wells in 2006 with mixed results, but after some trial and error, Range eventually applied a modification to the Mitchell Energy light sand frac called the slickwater frac, which turned out to be an effective production technique that is now commonly used on Marcellus Shale wells throughout the basin. The first successful horizontal Marcellus well, Gulla#9, came online in 2007, returning an initial gas production rate of 4.9 million cubic feet per day, which is quite exceptional for any gas well, and until then practically unheard of for a gas shale. Zagorski considers Gulla#9 to be the "discovery" well for the Marcellus Shale, and the one that started the play. Between 2008 and 2011, nearly 8,000 gas wells have been drilled and hydraulically fractured in the Marcellus Shale in Pennsylvania and West Virginia.

In addition to the Marcellus Shale, gas production from the Barnett Shale in the Fort Worth Basin of Texas is still going strong, as are the Haynesville and Fayetteville shales in Arkansas. The Woodford Shale in the Anadarko Basin of Oklahoma is also being produced. A new shale play getting started is the Utica Shale, an Appalachian Basin black shale that is deeper and older than the Marcellus. The Utica actually covers more land area than the Marcellus, extending farther into the northern, western and eastern reaches of the basin. It is already being explored and produced in Canada along the St. Lawrence River in Quebec. In eastern New York, it fills fault bounded valleys called grabens, sometimes to thicknesses of several thousand feet. The Utica also extends farther westward than the Marcellus into central Ohio. One advantage of producing gas from the Utica Shale is that it underlies the Marcellus Shale in many parts of the Appalachian Basin, making "dual completion" wells possible: i.e. two production targets from a single borehole.

Other shales of interest in the Appalachian Basin include the Rhinestreet and Ohio shales above the Marcellus. In Utah, gas potentials of the Mancos, Manning Canyon, Paradox, and

Pierre-Niobrara shales are being investigated. Alabama is looking into possibilities with the Floyd Shale and the Conasauga Shale. Well-known, organic-rich shales like the Antrim in the Michigan Basin, the New Albany in the Illinois Basin, and others are now being reviewed for their gas potential. Even the black shales in some of the small, Triassic rift basins along the U.S. East Coast are being evaluated for shale gas.

The Eagle Ford Shale in Texas produces significant natural gas liquids, or condensate, along with the gas. The liquids are worth more money than gas, and hence are more attractive to the petroleum industry, making the Eagle Ford the current "hot prospect" for shale drilling in the U.S. The Eagle Ford ranges in depth from about 2,500 feet to over 15,000 feet (760 m to 4.6 km), which has taken the shale through a variety of thermal maturation windows, from dry gas at the deep end through crude oil to "wet gas" at the shallower end. The Eagle Ford has problems with what is called retrograde condensate, however. Under reservoir pressures and temperatures, the natural gas liquids exist as a vapor phase, and come up to the surface as such, condensing out in tanks at the well pad. When reservoir pressures drop because of production, however, the vapors condense into liquids downhole, plugging up pores in the shale just like the light oil in the Huron Shale did for IGT. Trying to figure out how to produce both gas and liquid from such a reservoir without losing permeability is a major engineering and technical challenge. The locations of major shale gas plays in the United States (excluding Alaska and Hawaii) are shown on the map in figure 7 from the U.S. DOE Energy Information Administration.



Source: Energy Information Administration based on data from various published studies.
Updated: March 10, 2010

Fig. 7. Location of shale gas plays in the contiguous United States. Source: U.S. Department of Energy, Energy Information Administration.

3.2 Shale gas world-wide

Gas and oil production from shales is of interest worldwide. Many countries who once thought they were limited on conventional hydrocarbon reservoirs are finding black shales and exploring them for gas and oil. Active drilling projects are underway or planned in Britain, Canada, Ukraine, South Africa, several North African countries, and Argentina. Mexico, Belarus, Poland, Germany, Brazil, Australia and China are also interested in shale gas development. Once George Mitchell's ideas about how to horizontally drill and hydraulically fracture these rocks became known, the exploration of shale energy resources took off nearly everywhere (figure 8).

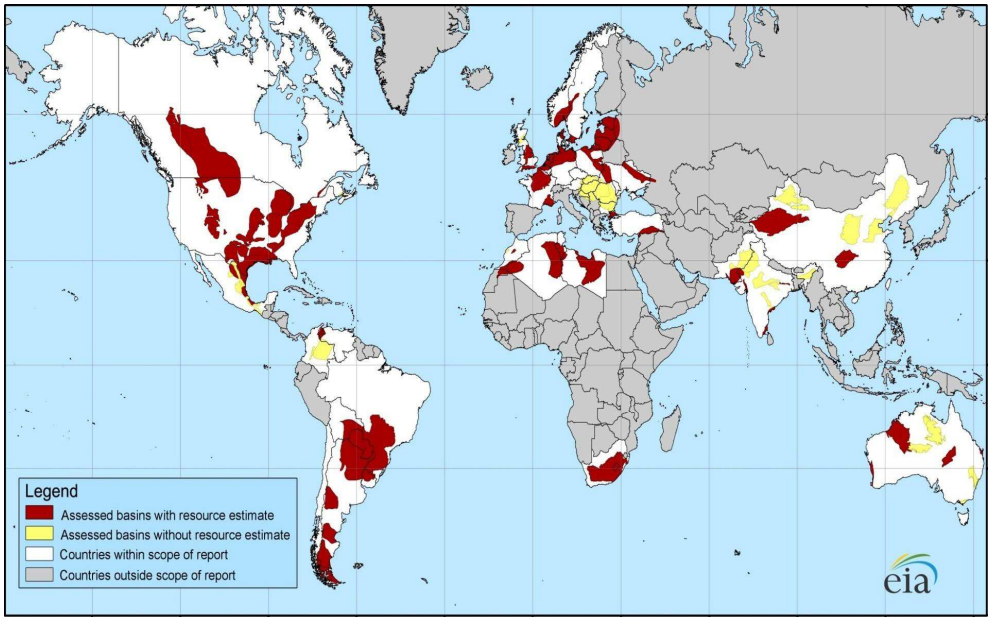


Fig. 8. Sedimentary basins worldwide containing significant shale gas resources.
Source: U.S. Energy Information Administration.

The resource numbers are enormous. Recent figures in some of the oil and gas trade journals suggest that shale gas reserves worldwide could be greater than 6,000 TCF, or more than ten to twenty times the amount of gas estimated for the Marcellus Shale, and possibly much higher. The amount of drilling, core sampling and well testing that has been taking place in most of these countries so far has been minimal, and data are sparse. Thus, most resource estimates are little more than educated guesses. In many countries, the geological thickness and extent of the organic-rich, black shale units are not known, so even educated guesses are not possible. Countries like Poland and Germany, who import most of their natural gas, are interested in developing domestic shale gas resources as a path to energy independence. However, environmental concerns over shale gas and particularly hydraulic fracturing are giving them pause. Environmental politics in the European Union are much stronger than in America, and sensitivities are higher. Countries are looking to the United States for environmental data and best management practices. Many are disappointed with the slow progress of shale gas environmental research in the United States.

4. Environmental concerns with shale gas

Development of shale gas is an industrial activity. Heavy machinery and serious equipment are needed to install the pad, drill down to the appropriate depths, and create and frac the long horizontal boreholes necessary for economic gas recovery. It involves a lot of material, including gravel, water, sand and chemicals for the pad and the hydraulic fracturing operations, along with many trucks to deliver all this to the well site. Installing the well creates noise, mud and dust, and requires a large crew of hard-working people, who live at the site for several days to weeks at a time. The drilling operations run 24/7, and create a neighborhood nuisance with their work lights, constant racket, smelly exhaust and endless activity. Having one of these sites near a home, school or business can be distracting, inconvenient, annoying, and disruptive.

Not all of the environmental impacts of shale gas production are known. A significant period of "baseline data" must be collected so the starting conditions are documented. Many of the parameters needed to determine environmental impacts have not been measured, because there has not been funding or time available to measure them.

Not all of the known environmental impacts are addressed under current regulations. Because the shale gas phenomenon is occurring in places that are not considered traditional oil and gas states, regulations that were largely designed for dealing with small drilling operations are inadequate for the scale of activity associated with shale gas development.

Not all of the current regulations are being properly enforced. State agencies don't have enough personnel to be everywhere all the time to enforce laws across extensive shale gas plays. Despite the huge upsurge in applications for drilling permits, the state oil and gas agencies have been largely unable to add a significant number of additional personnel because of tight budgets and other constraints.

Environmental impacts can be short-term or long term. Short-term impacts are related to well construction, and include things like water withdrawals, flowback fluid disposal, lights and noise from the drilling operations, effects of water impoundments on wildlife, and air pollution. Most of these go away once the well is constructed and all the equipment moves off, but they can be fairly intense during the drilling process. Long-term impacts are related to the well and drill pad occupying the landscape, and include concerns like habitat fragmentation, groundwater contamination from leaks or spills, the potential introduction of invasive species, and the process of ecological succession as the open drill pad slowly fills back in with vegetation. These factors are somewhat more difficult to quantify, and certain concerns, like invasive species, may not show up for some time. The short term impacts tend to be more acute, and the long term more chronic. Assessing both of these types of impacts is important for understanding the overall environmental effects of the gas well.

An additional unknown is cumulative impact, which stems from the planned development of the resource. Environmental effects from individual wells add up as more and more wells are placed within a tract of land, eventually taking conditions across a threshold and causing impacts much greater than the individual wells alone. At the rate the resource is being developed, tracts of land that were only going to contain a few wells have mushroomed into dozens. A problem with cumulative impacts is that it is difficult to tell when a threshold has been crossed until it is too late. Assessments need to be made of the number of wells an ecosystem or a watershed can tolerate per unit area.

The five things that are the most susceptible to the potential environmental impacts of shale gas development are air, water, landscapes, habitat and ecosystems. Quantifying the impacts of shale gas wells on these receptors could help significantly with the improvement of both environmental monitoring and management practices to minimize problems.

Air pollution during well construction and hydraulic fracturing is a concern because of the large numbers of diesel engines needed to run heavy equipment. Some drill rigs are now electric-hydraulic, drawing power from on-site generators running on natural gas supplied by a nearby well instead of diesel. Air can also be contaminated by exhaust from compressor stations needed to boost the gas up to pipeline pressures.

Water issues include potential impacts to water supply, water quality, and damage to small watersheds. These were described in a USGS publication by Soeder and Kappel (2009). The large volumes of water needed for a staged hydraulic fracture have the potential to impact local supplies. Many drillers now build large, central impoundments that they fill during times of high streamflow and low demand. Standards for the quality of water used in a frac have also been relaxed since drillers realized that swelling clays are generally not a problem in thermally-mature gas shales. They no longer require drinking water quality supplies for frac fluid. Recycled flowback and raw water from local streams is often used. Recycling the recovered high salinity flowback fluid into the next frac has lessened water quality concerns considerably. Still, the risk of spills and leaks, the potential for toxic metals and radionuclides to oxidize and leach from drill cuttings, and the movement of stray gas through aquifers remain water quality concerns. Small watersheds risk potential damage as drillers build five-acre drill pads and service roads. A great deal of equipment, supplies and vehicles have to be transported into and out of a drill site. Construction of roads alongside small streams often does not take stream hydrology into account, changing the flow regime and altering the aquatic ecosystem. Other watershed concerns include the potential for chemical spills, seepage of contaminants through shallow groundwater, erosion and sediment issues, and worries that high salinity flowback water could cause major mortality in aquatic ecosystems if released into a stream.

Habitat and ecosystem impacts near shale gas wells are both short-term and long-term. Short term impacts are related to the construction process itself, caused by the effects of lights, noise, activity levels, vehicle movements, and chemical exposure on local flora and fauna. Long term effects include re-occupation of the drillpad area by displaced plants and animals, species succession, potential impacts of structures and facilities on ecosystems, habitat fragmentation, and the possible establishment of invasive species. Many of these impacts are being assessed in a study being carried out in Pennsylvania (Soeder, 2010).

One of the popular concerns expressed about hydraulic fracturing is that the fractures may break upward into overlying aquifers, and contaminate groundwater with formation brines and dangerous chemicals. There are a number of physical reasons that make this highly unlikely; including the length of time the fracturing fluid is under pressure, the volume of fluid injected, the behavior of stress fields near the surface, and flow gradients once the well is in production. It is doubtful that the fluid will climb a mile or more against the force of gravity to contaminate a freshwater aquifer.

Geophysical data support the notion that hydraulic fracture heights remain well below freshwater aquifers. A technique called "microseismic monitoring," originally developed by

DOE and Sandia National Laboratory is used to determine the positions of hydraulic fractures in the ground. The method uses a string of sensitive microphones known as "geophones" that are suspended in a borehole near the frac location. The crackling sound emitted by the breaking rock is detected by the geophones and the arrival times of the sound at the different sensors are carefully measured. These data are then used to triangulate the progression of the frac over time. The vertical geophone string lowered into a well is said to be accurate to within a few cm on the height of the fracture. A graph from Fisher (2010) using microseismic data to compare the height of Marcellus Shale hydraulic fractures with the depth of the deepest aquifer reportedly producing drinking water on a county by county basis is shown in figure 9. In no case do the fracture heights approach within several thousand vertical feet (km) of the aquifers.

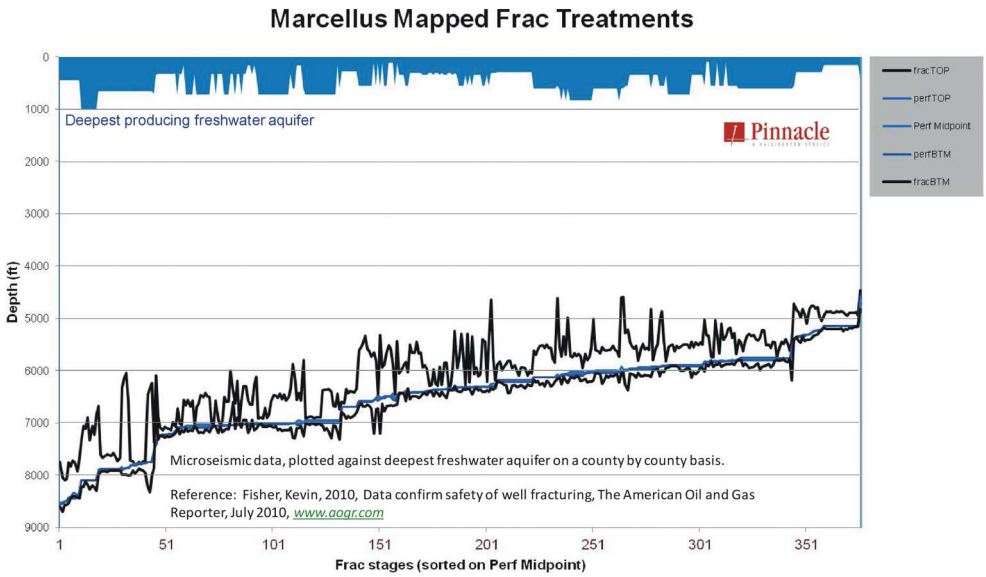


Fig. 9. Microseismic-measured height of hydraulic fractures in nearly 400 Marcellus Shale frac stages in numerous wells, plotted against the depth of the deepest freshwater aquifer in each county. For the figure, the fracs were sorted from deepest on the left to shallowest on the right. Data courtesy of Kevin Fisher, used with permission.

5. Conclusions

Organic-rich black shales contain significant amounts of energy in the form of natural gas, which may be large enough to make the United States energy independent for the first time since the 1950s, and finally bring to an end the so-called "energy crisis" of the 1970s. The size of the gas resource has been known or suspected for many years from government studies like the Eastern Gas Shales Project, but the technology needed to economically recover the gas was not developed until the 1990s. Mitchell Energy persisted with gas production attempts on the Barnett Shale in the Fort Worth Basin of Texas until they finally found a successful combination of horizontal drilling and staged hydraulic fracturing that allowed the recovery of large amounts of shale gas at economic costs. Range Resources was

the first to apply the Mitchell-developed technology on the Marcellus Shale in 2007, and started the current play. Shale gas development continues in the U.S. and worldwide.

The shale gas recovery process is not without environmental concerns. Environmental impacts on the Marcellus Shale include potential effects on air, water, ecosystems and habitat, some of which are known and others of which are still being studied. Improved drilling practices, such as frac fluid recycling, are reducing these impacts. There is reason to believe that all environmental impacts and indicators will be identified eventually, and properly regulated.

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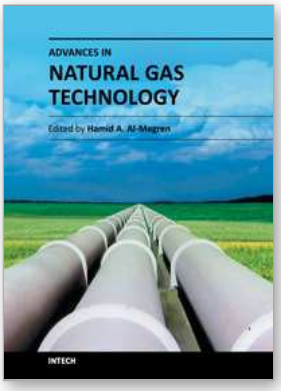

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Natural gas is a vital component of the world's supply of energy and an important source of many bulk chemicals and speciality chemicals. It is one of the cleanest, safest, and most useful of all energy sources, and helps to meet the world's rising demand for cleaner energy into the future. However, exploring, producing and bringing gas to the user or converting gas into desired chemicals is a systematical engineering project, and every step requires thorough understanding of gas and the surrounding environment. Any advances in the process link could make a step change in gas industry. There have been increasing efforts in gas industry in recent years. With state-of-the-art contributions by leading experts in the field, this book addressed the technology advances in natural gas industry.

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