3. Production of Marcellus Shale Gas

Production of the modern Marcellus Shale gas play began in 2005. Although the use of the word "play" to describe a resource may sound frivolous, in oil and gas exploration, play is a legitimate term defined as a group of drilling prospects with a geologically similar source, reservoir and trap, which control gas migration, accumulation, and storage (Patchen, 1996). In more practical terms, a play means finding out where other people are drilling successfully for gas or oil and drilling as close to that place as possible. Thus, a successful oil or gas well in one location brings in many others.

The twenty-first-century boom in shale gas drilling did not simply come about as a bolt from the blue (Carter et al., 2011). There were several decades of history leading up to it that included the development of new drilling technology, new methods for hydraulic fracturing, and a certain degree of persistence by a fellow in Texas named George P. Mitchell, who was determined to produce commercial amounts of gas from an organic-rich black shale in the Fort Worth Basin.

Innovation by industry and favorable economics moved shale gas development forward, although a certain degree of credit should still be given to government research programs like the EGSP and the MWX. Without the data from government-funded research, it would have been much harder for the operators to know that the unconventional resources were there and available for production. The public-domain reports and documents from this research were often the first places the drilling companies went for information on the shales.

Government scientific agencies exist to provide the types of data needed for policy decisions that industry does not normally collect. For example, the USGS was created in 1879 as the first government science agency because the U.S. Congress needed information about mineral resources in western lands made newly accessible by the expanding railroads. The railroads could not be counted on to supply this information in an unbiased manner, because they faced the potential taxation of any resources. Early USGS mineral assessments demonstrated to legislators the importance of obtaining accurate scientific data for the government to make sound decisions. Other data agencies like the National Weather Service, National Oceanic and Atmospheric Administration (NOAA), the National Institutes of Health (NIH), National Aeronautics and Space Administration (NASA), and DOE provide similar information.

Thirty years ago, shale gas was considered a marginal resource that could not be physically produced in large quantities, and even if it could, the economics would be awful. The drilling industry wouldn't go near it, except in very limited areas or as a secondary target. Yet, the government persisted in collecting research data on the shales, completing a resource assessment and characterizing the rock properties. Even though no one knew how to produce the resource at the time, it represented such an enormous potential reserve of energy that it was important to collect the information for future use. These data are what turned out to be so useful when the modern shale play started. Solar power satellites, geothermal power, ocean energy, fusion power, and several other potential future energy resources are in a similar position today.

Natural gas production from U.S. wells is traditionally measured in increments of a thousand cubic feet, abbreviated MCF. The "M" in the abbreviation comes from the Roman numeral for 1000. The metric equivalent of this volume is 28.32 m^3. At room temperature and atmospheric pressure, an MCF of gas would fill a space 10 ft high, 10 ft wide, and 10 ft deep ($3 \times 3 \times 3$ m), about the size of a small bedroom. A million cubic feet is a "thousand-thousand," so this is abbreviated MMCF using two Ms. Daily production amounts have a "D" on the end, such as MCFD or MMCFD.

Larger quantities of gas, such as the reserves remaining in the ground that have not yet been produced, are abbreviated differently: a billion cubic feet is BCF, and a trillion cubic feet is TCF. According to the Energy Information Administration (EIA), a total of 27,306,285 MMCF (27.3 TCF) of natural gas was used in the United States in 2015, the most recent year for which data are currently available (www.eia.gov/dnav/ng/hist/n9140us2a.htm; accessed January 2017). Some estimates for the total amount of recoverable gas in the Marcellus are as high as 500 TCF (Engelder, 2009), meaning that at current usage rates, the Marcellus Shale alone might be able to supply the entire United States with natural gas for nearly two decades.

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BACKGROUND

Back in the 1950s, George P. Mitchell (1919–2013) was working as a consulting geologist on oil and natural gas prospects and trying to get a drilling company started with his brother and a few other partners. The fledgling company, which would later become Mitchell Energy, got their big break in north Texas, hitting gas and oil in more than 30 separate fields that the Mitchell brothers had acquired on a supposedly worthless lease. By the mid-1960s, Mitchell Energy had become the nation's top independent gas producer. They merged with Devon Corporation in January 2002.

George Mitchell had been interested in the gas potential of the Barnett Shale since 1981. The Barnett is a black shale similar to the Marcellus that occurs in the Fort Worth Basin of Texas. The formation is named for a "typical exposure" of the unit at Barnett Springs, ~6.5 km (4 miles) east of the town of San Saba, Texas (Plummer and Moore, 1921). The Barnett Shale was assigned a probable late Mississippian age (326–318 Ma) by Sellards (1932).

Like the Marcellus and other black shales, it was difficult to obtain economical amounts of gas from vertical wells in the Barnett. Mitchell Energy tried several different drilling techniques and reservoir stimulation methods over a period of ~18 yr. These included massive hydraulic fracture stimulations like the one El Paso had done at Wagon Wheel in Wyoming, which did produce significant flows of gas but at very high cost. Still, George Mitchell believed in the potential of the Barnett Shale and continued to apply innovative technology to produce the gas.

Mitchell Energy had participated in the DOE EGSP under a cost-sharing agreement in 1978 to drill and core a number of shale wells in Ohio. In December 1986, DOE completed an experimental horizontal test well into the Huron Shale in West Virginia (Duda et al., 1991). This was the first horizontal shale well drilled with air instead of mud, and it was 610 m (2000 ft) long. The well was drilled in a direction perpendicular to the primary natural fractures with the intent of intercepting existing fractures and improving the efficiency of natural gas recovery. Mitchell Energy began experimenting with horizontal wells in the Barnett Shale soon afterward.

By 1997, Mitchell had perfected the more cost-effective "light sand" fracturing (frac) technique in vertical shale wells and started trying it in horizontal wells. The horizontal wells produced considerably more gas than vertical boreholes, because a horizontal well is able to contact much more of the shale rock volume. The runs of production tubing in horizontal wells were significantly longer than in vertical wells, however, and in order to reduce downhole pressure losses, a friction-reducing chemical such as polyacrylamide was added to the frac fluid to lubricate it, or make it "slick."

Thus, horizontal drilling and the staged, light sand slickwater frac became standard techniques for successfully producing commercial amounts of gas from shale in the early twenty-first century. (More details are given on the technology later.) A Barnett Shale gas drilling boom began in the Dallas–Fort Worth area in the late 1990s, including quite a few wells within the city limits of Fort Worth itself (Montgomery et al., 2005; Martineau, 2007).

George P. Mitchell received a Lifetime Achievement Award in Amsterdam on 16 June 2010 from the Gas Technology Institute for pioneering the hydraulic fracturing and drilling technologies that created the shale gas revolution. He died on 26 July 2013 at the age of 94.

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 action. Similar drilling booms followed on the Haynesville Shale in the Arkansas-Louisiana-Texas border region known as ArkLaTex, and the Marcellus Shale in Pennsylvania and West Virginia.

Range Resources began the modern, high-volume Marcellus Shale gas production in the southwestern corner of Pennsylvania, and they remain a major producer in the area. In 2005, Range Resources was drilling a well called Rentz#1 in Washington County, Pennsylvania, to test oil and gas prospects in the Lockport Dolomite, a Silurian-age (444–416 Ma) carbonate rock in the Appalachian Basin. It is older than the Marcellus Shale and located at greater depths.

The Lockport was originally deposited as a calcite-rich limestone, which was altered into a different rock called dolomite (named after the Italian mountains where it is common) by magnesium-enriched groundwater. The alteration process causes the calcite to recrystallize into a magnesium-calcium carbonate mineral also called dolomite (sometimes the rock is 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, and the process often creates open porosity that may contain oil and gas.

The presence of hydrocarbons in the pores is not guaranteed, however. A mantra of petroleum geologists is that despite all the expertise in geology, geochemistry, and high-tech geophysics directed at oil and gas exploration, they never really know what is down there until they get down there—and the only way to get down there is to drill.

The Rentz well came back with low porosity and 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 nonproductive, dry hole (Helman, 2010). Zagorski had graduated with a degree in geology from the University of Pittsburgh and spent 30 yr in the gas industry, so this was not his first gas well.

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 realized that he had seen evidence of gas in a section of the Marcellus Shale penetrated by the Rentz well above the Lockport Dolomite (Durham, 2010). He researched what was known about gas resources in the Marcellus, which included reviewing many of the old DOE technical papers and EGSP reports, and got the go-ahead from upper management to try to recomplete the Rentz well in the Marcellus Shale (Helman, 2010).

Range Resources recompleted and hydraulically fractured 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 Resources eventually developed a modification to the Barnett frac formula used by Mitchell Energy that was effective on the Marcellus. The first successful horizontal Marcellus well, Gulla #9, came online in 2007, returning an initial gas production rate of nearly 140,000 m^3, or 4.9 million cubic feet of gas per day, which is quite exceptional for any gas well and, until then, practically unheard of for gas shale. Zagorski considers Gulla #9 to be the discovery well for the Marcellus Shale, and the one that started the play.

Bill Zagorski received the Norman H. Foster Outstanding Explorer Award and was named "explorer of the year" by the American Association of Petroleum Geologists (AAPG) at their 2013 national meeting in Pittsburgh for his discoveries in the Marcellus Shale (Brown, 2013). An equally telling aspect was the fact that AAPG held their first-ever annual meeting in Pittsburgh (and the first one east of the Mississippi since 1986) almost entirely because of Zagorski's development of the Marcellus Shale and everything that followed.

Drilling

George Mitchell had discovered that one key to producing economical quantities of shale gas was the use of directional drilling to bore horizontally through the rock, which contacts much more formation volume than drilling vertically. The common black shale thickness of only a few dozen meters (a few hundred feet) limits the amount of contact a single vertical well can have with the formation. Changing the direction of a vertical hole to a horizontal boring allows the wellbore to remain within the shale for long distances, penetrating hundreds of meters or thousands of feet of rock. The drilling is coupled with hydraulic fracturing to create high-permeability flow paths into the shale. Instead of the single hydraulic fracs done in vertical wells, the long horizontal boreholes allow for an entire series of hydraulic fractures to be spaced a few dozen meters (a few hundred feet) apart. There can be 10 or more of these hydraulic fracture "stages" in a horizontal borehole, resulting in large volumes of gas production. A schematic diagram comparing the layout and configuration of a vertical borehole with a single hydraulic fracture and a horizontal borehole with multiple hydraulic fractures is shown in Figure 21. Drilling costs for a horizontal Marcellus well are ~2–3 times higher than for a vertical well, but the initial gas production potential can be 3–4 times greater (Engelder and Lash, 2008).

Directional drilling has its own set of terms (see Appendix A). The borehole is vertical until it reaches a predetermined depth above the target formation. This vertical stretch of hole is called the tophole. The depth at which the wellbore changes from vertical to some other orientation is the kickoff point. The location in three-dimensional space where the directional borehole intercepts the targeted producing formation is called the landing. The radius of the curve where the borehole changes direction from vertical to horizontal is known as the build or the build rate.

Directional drilling rigs used on the Marcellus Shale typically build a curve with a radius as tight as 150 m (500 ft). Sometimes they will build a reverse curve in the opposite direction called a sail to gain enough horizontal space to build the main curve for a proper landing on the target. The horizontal stretch of the borehole is the lateral. The path of the lateral through the target formation is known as the trajectory.

On a map, directional drilling in the Marcellus Shale is laid out in patterns that look like the legs of a spider. 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. The wellheads are spaced far enough apart at the surface to allow workover rigs and other equipment to have access. All the wells may be drilled immediately, followed by hydraulic fracturing and completion as a group, or they may be drilled and completed a few at a time because of limits on pipeline capacity or for other reasons.

Near the end of the EGSP and MWX projects, DOE looked into the applications of horizontal or angled drilling on a variety of unconventional oil and gas reservoirs. In addition to the horizontal Huron Shale test well in West Virginia (Duda et al.,

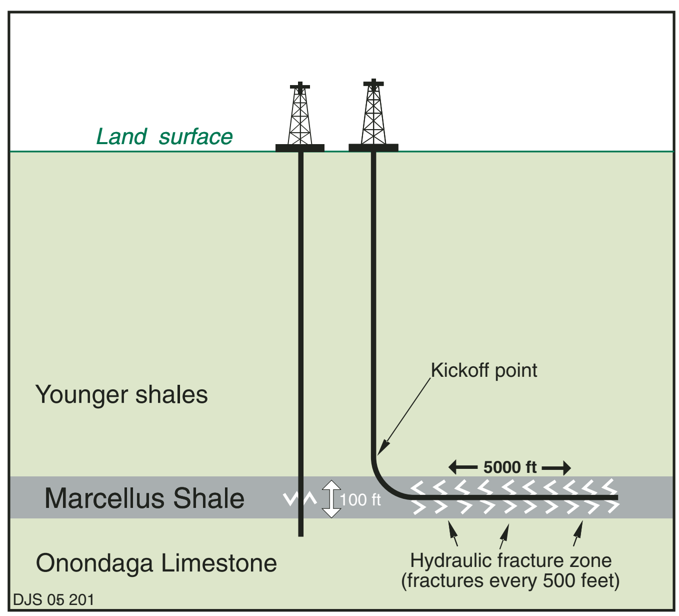

Figure 21. Illustration of the combination of horizontal drilling and hydraulic fracturing technology used for gas production from the Marcellus Shale in the Appalachian Basin. Horizontal wells have a much greater contact area with the shale than vertical wells, which are limited by the formation thickness. Figure is not to scale. Figure is modified from Soeder and Kappel (2009).

1991) described previously, an angled well was also drilled and cored at the MWX site in Colorado to intercept a vertical hydraulic fracture. DOE experimented with additional horizontal wells and multiple hydraulically fractured zones, working in collaboration with industry to develop the technology that would later be used to produce shale gas. Although these experimental wells were successful within their range of limited objectives, the widespread use of directional drilling and horizontal wells for shale gas production required better downhole sensors, improved electronics and communications, and some new thinking in drilling engineering.

These advances came about in the 1990s, driven by the needs of deep-water offshore oil drilling, and the larger fiscal resources available in this industry for research and development. 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 water a few dozen meters (a few hundred feet) deep. Drilling in kilometers (thousands of feet) of water required the use of semisubmerged, buoyant platforms held firmly in place by tensioned steel cables anchored into the seafloor.

When the rig needed to be moved, the old-fashioned steel towers could be floated a few meters off the bottom like an underwater skyscraper and towed with relative ease from one location to another. The tension leg platforms and their associated seabed anchor facilities, on the other hand, are much more elaborate and require manned submersibles and deep-sea diving technology to release the anchors and rig up at a new location. Moving these platforms is expensive and time-consuming.

Industry decided to pursue directional drilling as a solution. If a driller could bore a well directionally into one reservoir trap, and then drill another well in a different direction from the same platform location to intercept a second reservoir trap, a great deal of gas and oil could be recovered without moving the rig. The players in the deep-water drilling game were willing and able to spend the sums of money needed to develop and improve directional drilling equipment to make this a reality. Some deep-water platforms now routinely drill as many as 60 separate wells from a single location.

Although directional drilling had been around since the 1930s, there were two problems that needed to be overcome to make it practical: steering the bit, and knowing where it was located. When a kelly bushing is used to rotate the entire drill string from the surface to turn the bit, the borehole is not able to deviate much from a straight line. If a bend is too sharp, the rotating drill pipe will bind up and break. A more flexible drill pipe called a whipstock was introduced early on that was less prone to breaking, but it was still difficult to steer the bit and control the direction of the hole. The second major problem with directional drilling was that the driller had no way to accurately locate the downhole end of the borehole. There was not any way to tell from the surface, and early gyroscopes and telemetry were not very reliable.

The first technological advance in directional drilling was the downhole motor. U.S. patents for "self-propelled" drilling heads go back to at least 1949, where the idea was to supply power, either electrical or hydraulic, to some kind of downhole motor that would turn only the drill bit, eliminating the necessity of turning the entire drill string from the surface. Heavy steel drill pipe is flexible and can bend in a relatively tight radius without breaking if it does not need to rotate.

Most of the early downhole motor assembly designs were impractical. They tended to be large, inefficient, underpowered, and overheated easily. Once the deep-water oil companies dedicated significant financial backing to the efforts, the engineering and designs improved. A modern downhole motor uses hydraulic power, supplied by drilling mud pumped down the inside of the drill pipe under high pressure. There are several designs for providing power to the motor from the mud, ranging from spiral grooves built into the drill pipe to turbine-like spinning blades. The motor then turns the bit, which cuts the rock by using rotating steel and carbide teeth and applied pressure. The impeller, motor, and bit together are known as the "bottomhole assembly," and it is the only part of the drill string that rotates. With this configuration, wells can be drilled in virtually any direction, including horizontally. An example of a bottomhole assembly is shown in Figure 22.

Operators can steer the drill bit a number of ways. The simplest is to use a bent section of drill pipe near the bottomhole assembly to deviate the borehole orientation away from vertical (see Fig. 22). Drillers can also steer the bit by changing the pressure being applied against the cutting face or varying the rotational speed. Advanced bits have thrust bearings that can be controlled from the surface to change the angle of the cutting head, and thus the direction of the borehole. Some of the recent

Figure 22. Bottomhole assembly laid down at the surface, showing from left to right the green spiraled drill pipe that turns as high-pressure mud is pumped through it, a couple of connector pipes, and the red bearing assembly. The drill string above this does not rotate. The bent far end of the second red pipe from the right is used to build the curve for the lateral. Photograph is by Daniel J. Soeder.

advances in steering the bit now allow both the curve and the lateral to be drilled in one trip without having to pull the entire drill pipe out of the hole to change equipment after completing the curve. This saves time and improves the economics.

Drilling mud is not just a simple mixture of clay and water. It contains various stabilizers, lubricants, corrosion inhibitors, polymers, viscosity control agents, and other compounds, most of which are highly specialized and closely guarded trade secrets. Mud can be water-based or oil-based, including synthetic oil. Drilling mud serves multiple functions, including lubricating and cooling the bit, transporting rock cuttings back up to the surface, and maintaining enough pressure inside the borehole to prevent fluids from entering or the walls from collapsing. When used with a downhole motor, the pressurized mud also supplies hydraulic power to turn the drill bit.

The unit density or "weight" of the drilling mud is important for controlling the stability of a wellbore, and it is monitored and adjusted carefully. This is called balanced drilling. Mud weight is adjusted by adding minerals, typically barite, into the mud mix to increase the density, or water to lower it. Mud engineers track the pore pressures in the rocks, and the fracture gradient or rock strength. If the mud weight is underbalanced, or too low, oil and gas in the rocks can escape prematurely into the borehole, or the borehole walls could collapse. On the other hand, if the mud weight is too high, or overbalanced, it may exceed the hydraulic fracture gradient and crack the rock. This can result in drilling fluids moving into the formation, called lost circulation. The frac gradient and pore pressure vary with location and can even vary with depth in the same hole. Mud engineering is a precise science that requires detailed planning and a thorough understanding of downhole conditions to maintain a proper borehole.

Mud is typically pumped downhole through the inside of the drill pipe. It flows out of the cutter head through special vent holes or jets, cooling the drill bit and sweeping away the drill cuttings. The mud then returns to the surface through the annulus (the ring-like space between the outside of the drill pipe and the borehole wall), where it is captured and stored in a pit or tank until it is recirculated. The drill cuttings are filtered out through a series of vibrating screens called shale shakers, and they are analyzed by an on-site geologist or mud-logging engineer to confirm the geology of the formation being drilled. This can be tricky because it is difficult to pinpoint the exact depth where the cuttings originated. It depends on the penetration rate of the bit and the travel time needed for the mud to return to the surface.

Advances were also required in electronics and telemetry to accurately determine the length and direction of a horizontal borehole. In 1929, Sun Oil Company formed a joint venture with Sperry Gyroscope Company to apply Sperry's gyroscope navigation technology to directional wells. The new entity, called Sperry-Sun, sought to provide operators with real-time information called measurement while drilling (MWD). The concept combined gyroscopic compass readings and continuous data transmission that would allow the downhole location of the drill bit and the configuration of the borehole to be monitored. Unfortunately, the goals were somewhat lofty and ahead of the available technology, giving the system a reputation for being inaccurate and unreliable.

Sun Oil sold off Sperry-Sun in 1981. It evolved into Sperry Drilling and was bought by Halliburton. A reliable MWD system was available to operators by the early 1990s thanks to improvements in mechanical components and solid state electronics for inertial navigation. The interest from medium-sized operators to develop horizontal wells in the Austin Chalk also drove a lot of the navigational improvements that were later applied to the Barnett and other gas shales (Rao, 2012).

MWD consists of instrumentation that collects data on physical properties, such as pressure, temperature, and wellbore location, in three-dimensional space while drilling. The measurements are made downhole, stored in solid-state memory, and then transmitted to the surface at fixed intervals. Data transmission methods vary; one of the more common techniques digitally encodes the data and transmits them to the surface as pressure pulses in the drilling mud. Other approaches use sonic or electrical impulses through the drill pipe, or fiber optics imbedded in a nonrotating drill string for telemetry. MWD tools that measure formation properties, such as density, resistivity, sonic velocity, gamma ray, etc., are known as logging-while-drilling (LWD). Although the use of these systems is expensive, knowing the exact location of the borehole and the downhole physical conditions in near real-time can be invaluable.

Measuring the position of a bottomhole assembly that is kilometers below the surface is done by the determination of inclination and azimuth of the borehole. However, no matter how precise the measurements may be, small, systemic errors are compounded with depth, creating less precision for the measurement as holes grow longer. Instead of being plotted as a line, borehole positions are therefore drawn within "ellipses of uncertainty," which become larger with depth.

The maximum length of a lateral is determined by friction against the drill pipe. At some point, there is just too much drill pipe lying flat in a horizontal borehole for the driller to be able to push the bit any farther forward. Nevertheless, the lengths of some of these horizontal boreholes can be remarkable. The longest achieved so far onshore is the Eclipse Resources Purple Hayes #1 well in the Utica Shale, located in Guernsey County, Ohio, which is reported to have lateral length of 18,544 ft (3.5 miles or 5.6 km) and a total borehole length from the surface of ~27,046 ft or 8244 m (Beims, 2016). This is not typical for most Marcellus wells, although laterals half that length are common.

The laterals are drilled into the target shale in a direction that is usually perpendicular to the trend of the most prominent set of natural fractures, or joints. The idea is to drill across as many of these joints as possible and use them as a gathering system to help bring gas to the well. In the Appalachian Basin, the main joint sets in the Devonian black shales trend northeast to southwest (Engelder, 2009), so the Marcellus Shale laterals are commonly drilled on trajectories oriented either to the northwest or to the southeast. Laterals are often drilled parallel to one another at the optimal spacing for the most efficient recovery of natural gas from hydraulic fracturing. This varies from ~300 to 600 m (1000 to 2000 ft), depending on geologic properties of the rock and the type of frac treatment employed.

When several directional wells are drilled from the same pad, the positions of the vertical wells are controlled carefully to avoid interference. Once the kickoff point is reached, the wells diverge along horizontal trajectories designed to keep the ever-widening ellipses of uncertainty from touching one another. The art and science of driving directional boreholes sight unseen through deep layers of rock is called "geosteering," and the practitioners are extremely skilled.

Drill Rigs

Drill rigs come in a variety of sizes for different uses. Those used for drilling onshore prospects like the Marcellus Shale are known as "land rigs." The smaller types of these are mounted on trucks and can be moved about as a single unit. Larger land rigs are modular, and they are transported to a drill site as multiple components that are then assembled on-site.

Most modern drill rigs are powered by electric-hydraulic systems, using a bank of large diesel-powered generators to provide electricity for the rig's hydraulics. Because the Marcellus Shale is a continuous resource, many wells have been drilled in or near existing conventional gas fields to gain access to compressor stations and pipelines. A number of operators have modified their generators to run on the local natural gas supply instead of relatively expensive diesel. The Marcellus Shale play is located in an area that is industrialized and rather densely populated, and some operators have even been able to "plug in" their rigs to a nearby power line and drill using line power. Land rigs cost about $100,000–$500,000 per day to operate.

Historically, oil and gas drilling in the Appalachian Basin has employed relatively small equipment compared to the gigantic drill rigs common in Oklahoma, Texas, and the Louisiana Gulf Coast. Land-based drill rigs are classified by the height of the derrick, which determines how many 10 m (30 ft) segments of drill pipe (called "joints," not to be confused with the fracture joints described previously) can be recovered from a borehole with a single pull before being disconnected. Small rigs can only pull one joint of drill pipe at a time and are called "singles." Most of the Appalachian Basin drill rigs used in the past on conventional reservoirs could pull two joints at a time and are known as "doubles." The deep Marcellus Shale and the even deeper Utica Shale required the introduction of much larger rigs in Pennsylvania, Ohio, and West Virginia called "triples" (Figure 23).

Once the length of drill pipe reaches the top of the derrick, the bottom joint must be unscrewed or uncoupled and the pipe set aside, so the next segment can be pulled up. These pipe segments are stacked vertically in a rack, known as a stand, against the derrick. On a small metal platform near the upper part of the derrick called the monkey board, a rig hand fits the tops of drill pipes into the stand. This worker wears a special harness that can clip onto one of the slanted guy wires like a zip line in case a quick escape is required. If the drill pipe needs to stay out of the hole for any length of time, a hydraulic arm is used to transfer it from the stand into horizontal racks on the pad next to the rig.

The process of pulling pipe from the hole is called tripping out, and the fewer drill pipe joints that have to be unscrewed, the faster everything can be removed. Thus, drill rigs with taller derricks that can pull three or even four joints at once allow for faster trip times from greater depths. Drillers have to trip out to replace a worn or broken bit, install casing, run measurement tools down the hole on a steel cable, and sometimes to recover core or fluid samples. Casing is stored horizontally on the pad next to the rig platform and brought up to the rig floor one length at a time by the hydraulic arm for assembly and insertion. To trip back in and continue drilling, the threads on the drill pipes get some fresh lubricant (called pipe dope), the drill string is reassembled, and the whole process goes in reverse to get the bottomhole assembly back to the bottom of the hole.

The implement that actually cuts the hole is called the drill bit, or simply the bit. A conventional style is a rotary, tricone bit, which uses three rotating, interlocking cones with silicon carbide teeth to crush, break, and grind the rock. When cores are

Figure 23. A "triple" land-type drill rig in Greene County, Pennsylvania, with a derrick about 120 ft (37 m) high that can trip three joints of drill pipe at a time, shown in a vertical stack. The doghouse is visible to the left of the derrick. Photographed in 2011 by Daniel J. Soeder.

needed, a hollow bit is used that has a rim encrusted with carbide or industrial diamonds to cut rock. Oilfield cores range in diameter from 5 cm to 15 cm (2–6 in.), with 8.8 cm (3.5 in.) being the most common.

Shale drilling has become commonplace enough to have its own specialized bits. These generally consist of a one-piece steel body with fixed cutting teeth made of polycrystalline diamond composite (PDC). The PDC is a laminate of polycrystalline diamonds and carbide that is harder and more durable than carbide alone. These bits are designed to cut a smooth hole quickly, with directed jets on the face for high-pressure drilling mud to flush shale cake off the cutting teeth. Conventional drill bits commonly become bogged down by gummy mud from the soft shale. An interesting paradox in drilling is that soft rocks are often slower to drill than hard rocks.

The rig is operated from the doghouse, a small, office-sized trailer usually attached to the rig platform. Not long ago, a driller in the doghouse would control a throttle and a brake, and monitor the borehole depth and penetration rate with a simple pen on a drum recorder called the geolograph. Currently, the doghouse is loaded with computer screens, joystick controllers, and electronics. Feeds supply real-time data to engineers on-site and back at the home office on depth, temperature, weight on bit, rate of penetration, and other properties of the rig.

At the top of the hierarchy of workers at a drill site is the tool pusher, who is the operating company management representative responsible for overseeing the overall rig and site operations. The driller is the person who is responsible for and actually operates the drill rig itself. Drilling engineers assist by monitoring the rig performance and progress of the hole. The mud logger collects cuttings samples and keeps track of the geology being penetrated. The rig geologist is responsible for geosteering and guiding the trajectory of the lateral. Regular members of the rig crew are known as roughnecks. Crews are smaller these days because of hydraulics and automation. Crews typically live in trailers at the drill site, working 12-hour shifts. The length of time a crew member spends continuously at the rig is known as a tour (pronounced “tower”), which generally lasts one to two weeks.

Well Casing and Groundwater Protection

A gas well is much more complicated than just a hole in the ground. Because of the need to protect aquifers, and to keep gas, oil, and groundwater out of places where they do not belong, boreholes are lined with casing, held in place by cement. Casing is made of heavy, threaded steel pipe, which screws together in segments ~10 m (30 ft) in length. The connections have different styles of threads depending on the casing use, but most are a self-sealing type, like a tapered pipe thread. High-pressure casing uses flanges that lock together instead of threads.

Each length of casing, which is made up of joined segments of a uniform 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 to fit inside the others and extend to a greater depth. As each string of casing is placed in the hole, it is cemented into place. A proper cement job is critical for sealing the casing, and it is left to cure before drilling proceeds. Land-based wells like those in the Marcellus Shale commonly have two to four strings of casing, while offshore wells may have as many as 10 or 12.

Different casing configurations are used in different climates, but the following design is typical for Marcellus Shale wells in West Virginia and Pennsylvania. The initial penetration of the ground surface by a drill bit is called the “spud,” and it signals the start of the well. The hole only goes down to a depth of 10–20 m (30–60 ft), and then a large-diameter string of casing, usually ~60 cm (24 in.) wide, is installed as a mechanical barrier to support the sides of the hole in unconsolidated soil. This is known as the conductor casing.

The tophole continues downward through the shallow groundwater aquifers. This part of the drilling often uses an air-hammer rig, which links a pneumatic hammer action with rotation to quickly cut a clean, straight hole. At a depth of ~100 m (300 ft), drilling is paused, and a second, narrower casing string known as the surface casing (sometimes called the water casing or coal casing) is run and cemented in place from the bottom of the hole to the surface. This casing is usually 35–50 cm (14–20 in.) in diameter, and it is designed to isolate the gas well from the aquifers and coal seams. It is supposed to extend to the base of the deepest freshwater aquifer, but this exact depth varies with location and is highly debated. The casing protects the groundwater from gas or oil, and it also protects the well from being flooded by groundwater.

A brief discussion on the basics of groundwater may be helpful to some readers. The freshwater in the pores of soils and shallow rocks started out as precipitation that entered the ground under the force of gravity in a process called infiltration. The continued migration of water downward through the rocks and soil is called percolation. Both activities together are known as recharge. Water flows out of the ground naturally at springs and in perennial streams. The water present in a stream when it is not raining (i.e., when there is no overland runoff) comes from the seepage of groundwater into the stream channel. At shallow depths, the rocks and soil contain both air and water in the pores, but this becomes 100% water as one moves downward. The boundary between the unsaturated and saturated zones is known as the water table. The level of water in an undisturbed groundwater well generally sits at the height of the water table.

To provide a reliable drink, a supply well must be deeper than the water table, the depth of which varies over the course of a year; it is highest in the spring after being recharged with rain and melted snow and lowest during the dry months of late summer and early autumn. In establishing the depth of a water supply well, drillers must take this annual fluctuation into account or the well could be dry for part of the year. Rocks and sediments that are groundwater-bearing are called aquifers.

Because most sedimentary rocks were deposited on a sea bottom, the original water in the pores, called the connate water, was salty. These salts have been flushed out of shallow aquifers by the influx of fresh groundwater. With increasing depth, however, the water in the pores gets saltier, because freshwater only penetrates so deep. It is also less dense than saltwater, so freshwater tends to "float" on top of the deeper saltwater. The upshot is that drinkable or "potable" groundwater is limited in depth. A well that goes too deep will tap into the salty water below the fresh; the deeper it goes, the saltier it gets. Saltwater at depth is referred to as formation water or brine.

Salts in water are known as total dissolved solids (TDS). The U.S. Environmental Protection Agency's (EPA) secondary standard for TDS in drinking water is 500 mg per liter (mg/L). The drinking water standard differs from the EPA definition for the lower limit of "fresh groundwater," which is a TDS level of 10,000 mg/L, or 10 parts per thousand. Such water is brackish and undrinkable, with a salt content about one third that of seawater. The fresh groundwater standard comes from the EPA Underground Injection Control (UIC) program, which conservatively defines the levels at which groundwater must be protected from injected waste. EPA drinking water standards can be found online: https://www.epa.gov/ground-water-and-drinking-water/table-regulated-drinking-water-contaminants (accessed January 2017).

Most state regulations for protecting drinking water aquifers from oil and gas wells require that surface casing be set below the "deepest fresh groundwater." However, the base of the fresh groundwater is often not clearly defined. Attempts have been made to classify it as the deepest potable water, the deepest pumped aquifers within a county, or by a salinity or TDS standard, typically some fraction of seawater salinity. These regulations are developed at the state or local level, and they can vary considerably from place to place. As such, the requirements are ambiguous. Groundwater protection advocates want surface casing set as deeply as possible, but operators do not want to set any more casing than necessary because of the cost.

So how does all this apply to the development of the Marcellus Shale? Neither Pennsylvania nor West Virginia have strict construction standards for domestic water supply wells, which creates a wide variability of risk depending on the design of any particular well. Most domestic water wells are less than 100 m (300 ft) deep in West Virginia, and that is the typical depth for oil and gas well surface casing, including Marcellus Shale wells. The Commonwealth of Pennsylvania has been discussing groundwater protection standards for some time, but it has not been able to reach a consensus. Pennsylvania regulations call for surface casing to be set to depths of 50 ft (15 m) below the deepest fresh groundwater, defined as potable or usable. This depth has been highly debated, because the standard is somewhat ambiguous. The casing may go as deep as 200 ft (60 m) below the base of the fresh groundwater if necessary to reach consolidated rock (Commonwealth of Pennsylvania, 2011). Surface casings in Pennsylvania are typically set between ~500 and 800 ft (150 and 240 m) below the ground surface.

Regulatory authority for water withdrawals in West Virginia rests with the West Virginia Department of Environmental Protection. Pennsylvania is more complicated, with the eastern part of the state regulated by the Delaware River Basin Commission (DRBC), the central part of the state under the Susquehanna River Basin Commission (SRBC), and the Pennsylvania Department of Environmental Protection (DEP) responsible for the Ohio River Basin and the remainder. The protocols for determining allowable withdrawal amount vary, with the river basin commissions being the most rigorous.

Once installed, and before drilling proceeds further, the surface casing and cement undergo a casing integrity test (CIT). Also known as a leak-off test (LOT), this procedure applies pressure to the inside of the set and cemented casing in excess of the maximum hydrostatic pressure expected at the depth of the casing shoe, and monitors it for leaks (Syed, 2011). State and federal laws (30 CFR 250.427) require such tests to be run, and more elaborate tests can be compelled if necessary. Regulations prohibit continued drilling through bad casing, which must be replaced. There are also a number of downhole tools that can be employed if needed to evaluate the integrity of the cement.

The tophole drilling continues vertically until the kickoff point for the lateral is reached ~150 m (500 ft) above the target shale. A third string of casing, known as the intermediate casing, is then set and cemented in place. The role of this casing string is to prevent gas, oil, or brine in shallower formations above the target from entering the borehole and potentially migrating into other zones or the freshwater aquifers. The intermediate casing was often not used in the early days of the Marcellus Shale play, leaving exposed rocks in the vertical borehole. This led to some potential problems with gas migration into nearby water wells. Such "open-hole" completions are no longer considered best practice.

A final string of well casing, called the production casing, is installed in the finished hole. This is the slimmest casing string, usually only ~13 cm (5 in.) in diameter. It extends through all of the other casing strings 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. The production casing is cemented into place through the production zone to at least the base of the intermediate casing, although some operators may cement it all the way to the surface. This final casing string serves to channel all gas production directly to the surface inside a pipe, minimizing any opportunities to go astray.

Borehole Cement

The cement used in an oil or gas well is not like a bag of ready-mix sold at the local home improvement store. Oilfield cement formulas are specialized, taking into account the weight and viscosity of the drilling mud the cement must displace, and the pressures of fluids in the formation that it must hold back. Oil well cement is rated by the American Petroleum Institute (API) at different grades for various uses. When engineers design wells, they consider the various downhole conditions, such as the pump time needed to place the cement, downhole temperature, potential pressure effects, fluid loss, settling, and other factors that could affect the performance of the cement. The casing and cement are then specified for these particular well conditions.

Cement slurry is pumped down through the inside of the casing and distributed by a shoe at the bottom of the string so that it oozes up evenly into the annular space between the casing and the borehole wall. Spring-like centering collars are usually placed on casing strings at intervals to keep one string centered inside the next, which helps to ensure an even distribution of cement pumped inside the annulus. As the cement fills the annular space outside the casing from the bottom upward, it displaces the drilling mud out of the hole.

A number of failures can occur during this step (Dusseault et al., 2000). If the viscosity and density of the cement are too different from the mud, the cement will not displace the mud uniformly, but push into it as a series of fingers. This can trap pockets of fluid in the cured cement, creating channels for flow. Fingering can be minimized by pumping the cement in slowly, but pumping it too slowly leads to another problem called static settling, where the slurry begins to separate out into water and solid components. Elevated downhole temperatures can cause the cement to set up more quickly than planned, reducing the time available for pumping. Angled or horizontal wells can have the fluid and solid phases in the cement slurry separate through a process called dynamic settling. Fluid loss from the slurry into permeable formations can result in thickening times that are too short, and changes in downhole stress as the well is produced can also cause cement instability.

Most cement failures do not occur within the cement itself, but at the bonding interface between the cement and casing or between the cement and borehole wall. Contamination of the slurry with small amounts of oil, excessive casing vibration, or failure of the cement to bond to preservative coatings or grease on the outside of the casing may create a microannulus, a small, concentric, vertical crack that allows fluids to migrate.

One mitigation method under investigation is foamed cements, which contain up to 20 percent volume nitrogen gas bubbles (Kutchko et al., 2012). Similar to the expanding plastic foam used to seal doors and windows, foam cements are less dense, and they have better space-filling and sealing properties than plain cement. The ideal foam cement contains the maximum number of gas bubbles possible in a given volume with enough cement remaining between the bubbles to keep them separate. Interconnected bubbles would be a disaster, creating flow paths throughout the cement.

If well cement does fail for whatever reason, fixing it can be an expensive and tedious task. Drillers would much rather get the cement right the first time. Bad cement may require that the well casing be pulled and reset. If this is not possible, another option is to repair the cement in place by perforating the casing and pressure-injecting new cement behind it in an operation known as a “squeeze job.”

When all goes well, the weight of the cement compressing the elastic steel casing ensures a tight bond between the cement and the casing as it cures. The integrity of the bond can be checked by a variety of methods. One common physical test is a pressure evaluation, such as a shoe top casing test or a liner top test, both of which are designed to determine if the cement is holding a seal. Another frequently used physical test is a temperature log—as the cement cures, it undergoes an exothermic reaction, releasing heat. Measuring the temperature on the inside of the casing is usually sensitive enough to detect the top of the cement. Some more esoteric tests use radioactive tracers and electromagnetic techniques, but these are expensive, rare, and generally only applied in special circumstances.

The most common method for checking the integrity of a cement job in a well is called a cement bond log. These are carried out using acoustic well log tools. There are three main types: (1) a tool that measures sonic impedance or loss of signal, (2) an ultrasonic imager, like a medical ultrasound, that can view gaps or voids in the cement behind the casing, and (3) a passive listening tool that can detect fluids moving behind the casing.

The impedance tool works on the principle that poorly bonded pipe will vibrate more freely than firmly cemented pipe, like the ringing of a free-standing wine goblet versus one held tightly in the hand. The data must be interpreted with caution because the engineering calculations, which were developed in 1960, contain some assumptions. The tool consists of a receiver placed a fixed distance below a transmitter. The calculation assumes this distance is unchanging, the cement has a known strength, the casing is centered in the well, and the formation is uniform. The methodology provides a number called the cement bond index, but most engineers caution that it should only be used in combination with other tools.

Ultrasonic imaging tools employ an unfocused transducer and a resonance technique similar to medical imaging. The tool rotates rapidly as it moves, capturing many readings per revolution. It can detect the difference between fluid behind casing and solids behind casing and produce images of voids and channels.

Cement bond analysis using any of these tools requires knowledge about the specifics of the individual cement job: slurries pumped, when and how fast, formations involved, length of set times, downhole temperatures, annulus size, and so on. Without this information, evaluating the cement job is difficult and subject to interpretation errors. The best way to reduce uncertainty in the interpretation is to run multiple tools that use different methods to measure the cement integrity. Few companies do this, however, because it is a significant added expense. Nevertheless, casing and cement are used to isolate the wellbore from the surrounding formations, and demonstrating such isolation is critically important to well integrity.

HYDRAULIC FRACTURING

Hydraulic fracturing is not a new technology. It was invented by Floyd Farris of Stanolind Oil and Gas Corporation in 1947, based on the results of a series of field experiments to fracture rocks using crude oil and naphtha gels in the Hugoton gas field in

Grant County, Kansas. The modern, water-based technique was developed in 1953 (Montgomery and Smith, 2010). A patent was issued in 1949, granting exclusive rights for the Stanolind process to the Halliburton Oil Well Cementing Company. The first commercial hydraulic fracture stimulations were performed in 1949, using oil-based frac fluids on a well in Duncan, Oklahoma, and another well in Holliday, Texas (Fisher, 2010). Hydraulic fracturing was first applied to wells in Pennsylvania in December 1953 (Carter et al., 2011).

It is important to note that the term "fracking" is often used to describe the entire shale gas development process by some who oppose it. The overall shale gas development process consists of drilling, completion, stimulation, and production. The shale gas industry considers the frac (spelled without the "k") to be the stimulation stage of development, and just one component of the total process. The imprecise use of "fracking" has resulted in a number of misunderstandings between shale gas proponents and opponents.

The completion stage of a well begins by creating holes or perforations through the production casing to allow the gas to enter. This is done using a perforating gun or "perf gun." In the old days, actual bullets were employed, hence the name. Modern perf guns use shaped charges consisting of up to 60 g of cyclotrimethylenetrinitramine, more commonly known as Royal Demolition Explosive (RDX), or other military-grade high explosives. The detonations create holes in the casing between 6 and 20 mm (¼ to ¾ in.) in diameter, with a depth into the rock from 10 cm to >1 m, and there are generally 12–36 holes created per meter (4–12 holes per foot). Successive shots are turned at an angle of ~60° from the previous shot to spiral the holes all around the casing.

A perf gun is composed of a carrier unit containing explosive charges attached to a detonation cord, and a remotely operated detonator that sets off the array of explosives simultaneously. The guns are designed to contain the explosive debris so that it can be removed from the well. Once a segment of production casing has been perforated, a pathway exists for frac fluid to enter the formation, and for oil or gas from the formation to flow back along the fractures, through the perforations, and up to the surface.

Hydraulic Fracturing Chemicals

The components of a hydraulic fracturing operation consist mostly of water, proppant sand, and a fraction of a percent of chemical additives. Chemical information about these additives is posted on the Frac Focus website (http://fracfocus.org/; accessed 17 January 2017), voluntarily in some cases, and required by state permit in others. Although the chemicals are used in low concentrations, they are deployed at the drill site in large volumes. This is because the water, chemical, and sand mix is blended during the progress of the frac, where the types and amounts of chemicals added may change over the course of the stimulation. An examination of the Frac Focus website indicates that the most common chemical additives to frac fluid include methanol, isopropanol, crystalline silica, 2-butoxyethanol, ethylene glycol, hydrotreated petroleum distillates, sodium hydroxide, hydrochloric acid, ammonium chloride, ammonium and sodium persulfate, glutaraldehyde, and polyacrylamide (Soeder et al., 2014b).

The U.S. Environmental Protection Agency (EPA) compiled a consolidated list from federal and state government documents, industry-provided data, and other reliable sources of 1,173 chemical compounds used or found in hydraulic fracturing (U.S. EPA, 2016). Chemical additives are used to clean the perfs, reduce friction losses downhole, provide corrosion resistance, inhibit scale buildup, and suppress downhole microbial growth. The complete list of chemicals can be found in a database associated with the EPA hydraulic fracturing drinking water impacts report, available online: https://www.epa.gov/hfstudy (accessed January 2017).

One of the primary chemical additives to frac fluid is polyacrylamide, a friction reducer. This dry powder material creates an extremely slippery liquid known as "slickwater" when mixed with water. Slickwater is used to reduce pressure losses due to friction as the frac fluid is pumped to the formation down a long string of production casing. Downhole pressure losses affect the type of equipment and pressure ratings needed at the surface, and they are described in more detail in the next section.

The biocide is probably the most hazardous of all the chemical additives in use. Biocides come in two general types: oxidizing or nonoxidizing (Kahrilas et al., 2015). Oxidizing biocides (such as bleach, peroxide, etc.) attack microbes, but they also corrode equipment and damage rock formations. As such, most hydraulic fracturing operations use nonoxidizing biocides. These fall into two classes: lytic biocides that act by dissolving the cell walls of bacteria, and electrophilic biocides that act by binding themselves to bacterial cell walls (Kahrilas et al., 2015).

Biocides are necessary because if not repressed, bacteria introduced downhole with the frac fluids can consume organic and sulfate compounds, creating hydrogen sulfide gas (H_2S) as a by-product. The H_2S causes the production gas to be "sour" and corrosive. It must be removed before the gas can be sold to a pipeline. H_2S is also toxic if inhaled, so preventing it from being generated is important. Alternatives to biocides, such as treatment with ultraviolet light and other options, have been tried, but they have not been found to be as economical (Kahrilas et al., 2015).

The claim that "hundreds" of chemicals are added to frac fluid is a misunderstanding. While a great many chemicals have been tried over the history of hydraulic fracturing, no one adds hundreds or even dozens of chemicals to any individual frac. Advances in hydraulic fracturing technology have reduced the total number of chemicals used to maybe a half dozen in a single frac. Different chemicals may be used in different frac stages, but only a few are used in each (Soeder et al., 2014b). Many of the chemicals present in groundwater that people blame on Marcellus Shale hydraulic fracturing are actually coming from elsewhere. This is discussed in more detail in the Contaminant Hydrology section in Chapter 4.

Shale fracs tend to use less proppant sand than other kinds of fracs to maintain open fractures after pressure is released.

These so-called "light sand" fracs are more effective on shale, and they also minimize the use of viscous gels like guar gum to carry in proppant. Nevertheless, because of the high volume of hydraulic fracturing in shale, even light sand fracs end up using a lot of sand, which is required to be composed of evenly sized, well-rounded, and high-compressive-strength quartz grains to work well as a proppant. The Jordan Sandstone in Wisconsin is one of the few formations that consistently meets these standards. Concerns have been raised about the damage to landscapes from the extensive mining of this frac sand (Parsen and Zambito, 2014).

Compounds known as "cross-linked gels" are used on some fracs for proppant transport, but these generally require a second chemical called a "breaker" to reduce the viscosity and allow the liquid to flow back out of the fracture. This adds costs, and the potential human and ecosystem health impacts of many of these chemicals are unknown. Short-half-life radioactive tracers such as iodine or antimony isotopes are also sometimes added to the proppant to allow the height of the hydraulic fractures to be traced in the subsurface (Smith and Montgomery, 2015). The use of these tracers is common in vertical wells, where a wireline gamma log can be employed to detect the top and bottom of the propped fracture. In staged fractures along shale laterals, microseismic monitoring is a more effective technique.

Hydraulic fracturing in shale requires less proppant because "asperities" or natural rough spots are created on fracture walls that help prop open the fracture when pressure is released. Proppant sand often has a problem called "embedment" in shale, where the hard quartz sand grains simply sink into the softer shale without propping open the fracture. Natural asperities in the rock essentially place shale against shale, reducing embedment.

The Hydraulic Fracturing Process

A special high-pressure wellhead designed for hydraulic fracturing is known as a frac gate. This is installed at the surface, just above the main casing to allow equipment and materials carried by wireline to pass through, as well as to control the entry and exit of fluids on the well. A photograph of a frac gate is shown in Figure 24A, where it is compared with a typical natural gas production wellhead, known as a "Christmas tree" (Fig. 24B).

The main wellhead pressure valve at the top of the production casing string is left wide open during the frac job, because the proppant sand being pumped downhole and returning afterward would abrade any obstruction in its path (this valve can be seen in Figure 24A immediately below the frac gate). Abrasion by moving sand is a concern in all stimulations. Although the production casing is typically made from 1.25-cm-thick (0.5-in.-thick), API-rated, high-tensile-strength steel pipe, there have been rare cases where a hole was abraded in the curved part of the casing during the frac by sand particles racing through the turn.

Hydraulic fracturing operations in horizontal boreholes in a gas shale are carried out in stages. The stages begin at the end of the lateral, called the toe, and work backward in increments of ~150 m (500 ft) toward the upward curve or heel. Each stage receives a hydraulic fracture treatment, which is then blocked off while the next stage is treated. When all the stages are completed, the barriers between stages are removed and production begins. The longer the lateral, the more fracture stages are needed. Marcellus Shale wells with 15–20 hydraulic fracture stages are not unusual. The Utica Shale superlateral in the Eclipse Resources Purple Hayes #1 well described previously is reported to have had 124 individual frac stages (Beims, 2016).

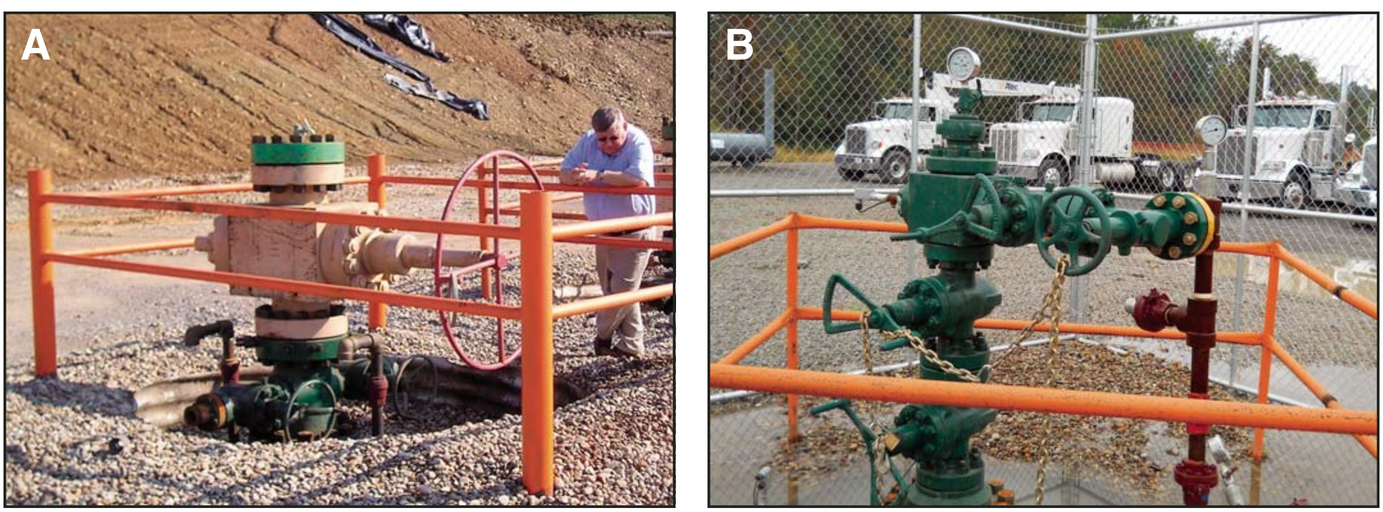

Figure 24. (A) Geologist Bill Schuller for scale next to a massive frac gate wellhead on a recently drilled Marcellus Shale well in Greene County, Pennsylvania, prior to hydraulic fracturing. The green main casing valve can be seen below it. (B) A much less massive production wellhead (i.e., Christmas tree) on a producing Marcellus Shale gas well. The orange cages protecting both are the same height. Photographed in 2011 by Daniel J. Soeder.

Once all the materials, fluids, pumps, and other equipment are set up on a well pad, the hydraulic fracturing process begins by cleaning out the perf holes using a 15% solution of hydrochloric acid. Perforating casing with high explosives tends to jam pieces of steel and pulverized cement into the formation, and these need to be removed to open up the perf holes. After the acid is pumped down the well, the hydraulic fracturing system undergoes pressure testing, and all the equipment is calibrated.

The high- and low-pressure systems on a frac are plumbed separately, so fluid from one cannot get into the other unless the operator allows it. The working parts of the pumps used to generate the frac pressure consist of positive-displacement pistons inside high-pressure steel cylinders. The rate at which these pistons advance can be controlled very precisely to maintain a specific flow volume and/or pressure. The pumps have safety cutoffs if pressure or volume parameters are exceeded, and the high-pressure parts of the system also have relief valves to prevent critical components from blowing out.

The frac fluid is mixed in a blender, including the proppant sand, which is added by an auger feed. As the hydraulic frac begins, the pump rate is brought up slowly. Real-time measurements collect pressure data at the wellhead, downhole, and in the annulus behind the production casing. 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 closely watch the wellhead, annulus, and bottomhole pressures, pump rate, fluid density, and material parameters throughout the frac (Figure 25).

The pressure on the frac fluid is increased until it exceeds the formation strength and the rock cracks. This is called breakdown. Because water is virtually incompressible, as soon as the fractures are created and water begins flowing into them, more water must be added at the surface to maintain the pressure. The initial part of the fracture, called the pad, is made with slickwater only. Behind this, as the fracture opens up, sand is pumped in with the water to act as a proppant. The rate at which the sand is pumped is critical—too fast, and the proppant will be spread too thinly in the formation; too slow, and the proppant will not remain in suspension in the frac fluid, settling to the bottom of the well in a process called a screen-out. Fine-grained proppant is pumped into the fracture initially, followed by a coarser proppant as the fracture system develops.

Water pressure and pump rates are maintained until the hydraulic fractures extend outward to distances as great as 300 m (1000 ft) from the well. The growth rates and lengths of fractures can be measured using a geophysical technique called microseismic monitoring. The fractures themselves do not have to be especially large to create high-permeability flow paths for gas in these ultratight rocks. Some of the permeability experiments at IGT (Soeder, 1988) suggested that the most important fractures for gas movement in shale were barely visible hairline cracks, not the large, calcite-filled veins sometimes prominent in cores.

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 zone from the rest of the well. These are typically solid cement or composite plugs, but some newer designs use a donut-like rubber

Figure 25. A hydraulic fracturing operation in progress on a Marcellus Shale well in Greene County, Pennsylvania, October 2011. The pump trucks are to the right of the two massive wellheads, and the proppant sand is in the tank with the two men on top. The water was in a large impoundment behind the photographer, supplied to the pad through surface pipes. Photograph is by Daniel J. Soeder.

cylinder called a packer equipped with a check valve that closes off the downhole treated zone against frac pressure in the next zone, but allows fluid and gas to flow uphole during production.

The perf gun is reloaded and lowered back into the well, where a second set of perforations is shot into the next length of casing. The hydraulic fracture treatment is repeated in this second stage, which is then closed off with another bridge plug or packer. The process continues stage by stage until the heel is reached. Depending on the size of each stage and the length of the laterals, a typical shale gas well hydraulic fracturing process usually takes about a week to 10 d to complete.

One of the issues that engineers worry about when designing hydraulic fracturing treatments is the loss of downhole pressure due to friction. A Marcellus Shale horizontal well 2300 m (7500 ft) deep and with a lateral 2100 m (7000 ft) long requires frac fluid and proppant to be pushed through 4.5 km (nearly 3 miles) of 13-cm-diameter (5-in.-diameter) pipe to reach the first stage near the toe. A pressure of 83,000 kPa (12,000 psi) applied to the frac fluid at the surface may only be about half of that, or 41,500 kPa (6000 psi), down at the toe of the lateral.

There are limits to the pressures that can be applied at the surface—if the required pressure exceeds the pressure ratings of standard equipment, then higher-pressure-rated valves, tubing, and casing are needed, which drives up the cost. Larger-diameter production casing will transmit pressure better, but the larger volume also requires more or bigger pumps to achieve flow rates that will keep the sand in suspension and avoid a screen-out, which also adds to the cost. The trade-offs among expected production, stimulated reservoir volumes, frac pressures, pump rates, tubing and casing strength, equipment requirements, volumes of materials, and costs are juggled daily by the financial people and engineers at production companies and service companies who plan hydraulic fracturing.

Gas in the Marcellus Shale is "overpressured," which means that the initial gas pressure in the rock is higher than the hydrostatic pressure imposed by the column of frac water filling the well (Wrightstone, 2008). The gas pressure is therefore able to push the frac fluid out of the well in a process called "blowback," which is designed to get as much of the liquid out as possible.

The expelled fluid is diverted into a holding tank or pond through a pipe called the "blooey line." Because the well is not yet in production, in the past, operators typically disposed of the gas that came up with the fluid by burning it off or flaring. The blooey line was fitted with a flare bucket, generally a metal can filled with burning, diesel-soaked rags hung on the end of the pipe to ignite any gas. Flaring is no longer permitted under recent revisions to the U.S. Clean Air Act, New Source Performance Standards (40 CFR Part 60, 2011; see https://www.gpo.gov/fdsys/pkg/CFR-2011-title40-vol6/xml/CFR-2011-title40-vol6-part60.xml [accessed 3 February 2017]) for wells to which these standards apply.

The water returned from the well after hydraulic fracturing is commonly referred to as "flowback fluid," although this term has acquired regulatory meaning, and many researchers now prefer the more generic term "produced water." In Marcellus Shale gas wells, the returned fluid typically starts out as relatively fresh water containing compounds from the fracturing fluid, and it becomes increasingly salty over time (Hayes, 2009; Soeder and Kappel, 2009). Some people still make a distinction between the returned fresh water used in the frac as "flowback" and the saltier water from the formation as "produced water." It is important to be aware of these conventions when reading the literature.

After the initial return of fluids, the flow of liquid may persist intermittently for weeks. Current practice for many operators is to filter out suspended solids and recycle the lower-salinity produced water into another frac to reduce the waste volume and minimize the costs of disposal. High-TDS produced water that cannot be reused is called "residual waste" and is usually injected down Class II UIC disposal wells (Maloney and Yoxtheimer, 2012). Residual waste is a term used for waste produced by industrial processes, to distinguish it from municipal waste, produced by commercial and residential processes.

It is important to note that residual waste is not classified as hazardous waste. Hazardous wastes are regulated under Subtitle C of the U.S. Resource Conservation and Recovery Act (RCRA), while residual wastes are managed by state authorities under approved waste plans. While all oil and gas exploration and production wastes are exempted from the hazardous waste definition, EPA has published guidance encouraging operators to manage these wastes appropriately based on their characteristics, which in some cases would qualify these materials as hazardous waste if no exemption were provided.

Once gas production starts, the frac gate is replaced by a much less massive production wellhead called the Christmas tree (refer back to Fig. 24). The outflow line from the Christmas tree goes through a gas-water separator, which is a tall, narrow tank with an outlet at the bottom for water and one at the top for gas. Gravity is used to separate the two fluids. The gas is further processed through ethylene glycol dryers to remove any remaining traces of water vapor before it goes into the gas transmission pipeline.

Water in gas pipelines must be avoided—under high pressures and low temperatures, it will form a solid, waxy, ice-like compound called methane hydrate, which incorporates methane gas as part of the crystal lattice structure. Methane hydrates occur naturally in cold, high-pressure environments like the bottom of the ocean or under Arctic permafrost, and they have been investigated by DOE for years as a potential energy resource. If water enters a high-pressure gas transmission pipeline, and it gets cold, the resulting hydrate formation can completely block the pipe, which does not endear a gas producer to a transmission company.

PRODUCED FLUIDS

There are a number of mysteries associated with produced water from gas shales in general, and the Marcellus Shale in particular. The first is why so little is actually recovered. Generally, less than a quarter of the frac fluid (some estimates are less than 10%) used on the Marcellus returns as flowback (Zhou et al., 2016). This actually varies with location in the play; in some areas, the Marcellus Shale returns more water than in others.

Other shale plays return varying amounts; many return less than half, but some shales produce more water than was injected.

No one is sure what happens to the frac water that remains downhole in Marcellus Shale wells. Some people think it enters the pores of the formation, while others suspect the water works its way downward under gravity into the bottoms of the fractures and stays there. It is also possible that the warm temperatures at depth and the large volumes of gas flow from Marcellus wells may return a significant portion of the water to the surface as vapor in the produced gas stream. Whether or not this actually happens is debatable, and accurate measurements of water volumes recovered over long time periods are needed to determine the mass balance.

The physics suggest that the gas flow pushes a portion of the fluid up the hole until the liquid phase becomes discontinuous, at which point it is no longer mobile. The gas will continue to push some individual slugs of water up to the surface for an additional time period, but it presumably flows around and past most of the discontinuous remaining liquid.

Some interesting anecdotes have been told about shale gas wells that were drilled and fractured to meet lease obligations, but then had the wellhead valves closed or “shut-in” for 6 mo to a year waiting for pipeline construction to get to the location. When these wells were finally opened up for production, the amount of gas produced and the decline curves of gas production were significantly different than for wells that had been produced immediately after hydraulic fracture treatment. Many of the shut-in wells actually produced higher rates of gas, but some were also lower. Presumably, the shut-in wells had time for the frac fluids to migrate and settle differently than the wells that were produced immediately. Adjustment of the flow system to stresses from the frac might be another factor. Shut-in wells also typically produce less water overall, suggesting that a significant amount of it has actually migrated into the pore system.

A second mystery about the produced water is the high salinity. In 2008, a group of gas production companies formed a consortium called the Marcellus Shale Coalition, which funded the chemical analysis of produced waters recovered from a number of Marcellus Shale wells owned by the different member companies. The GTI ran samples from a total of 19 Marcellus wells through a commercial water analysis laboratory following EPA protocols. GTI concluded that the produced water had a TDS composition similar to other Appalachian brines but at higher concentrations (Hayes, 2009). The TDS content of Marcellus Shale produced water was found to be as high as 200 g per liter (g/L), or about six times saltier than seawater. Chloride was present at more than 100 g/L, and various metals were present at hundreds of milligrams per liter.

A related mystery of produced water is the often unusual chemical composition of the TDS. Marcellus Shale waters typically contain concentrations of barium (Ba), strontium (Sr), and bromine (Br) at levels considerably higher than ocean water. It is unclear how the original connate water might have been fractionated to reach such extreme increases in salinity. A study by McIntosh (2012) found that the high bromine to chlorine ratio indicative of Marcellus Shale produced water may have been caused by evaporation of seawater past the sodium chloride (halite) saturation level. Sodium chloride concentration could not increase beyond this point, but other dissolved anions, such as bromide, could have continued to concentrate.

The high TDS of the produced water apparently reflects the very salty formation brines within the shale itself (McIntosh, 2012; Rowan et al., 2015; Stewart et al., 2015). Formation brines occupy a relatively small percentage of the pore volume in gas shales (Engelder, 2012) and are generally a nonmobile fluid phase in these rocks. Since the days of the EGSP, it has been noted that Appalachian Basin Devonian shales rarely, if ever, produce any water (Soeder et al., 1986). This does not mean that the shales are dry, just that whatever water is in them is not mobile. Water may be present as layers of hydration on clays, for example, or as disconnected brine droplets in isolated pores that are unable to flow. Frac water entering the formation may contact this preexisting water and pick up the salts.

It is possible that osmotic forces equilibrate salinity through the migration of high TDS from the brines into the freshwater frac fluid (Blauch et al., 2009). This would be a relatively slow process in porous media, especially in tiny shale pores, and it may explain why salinity in the produced water typically continues to increase over a period of weeks before reaching a plateau. However, geochemical trends of major elements (Haluszczak et al., 2013) and oxygen isotope data (Warner et al., 2012) in produced water are generally not consistent with this interpretation.

Formation water in the Oriskany Sandstone, below the Marcellus Shale, is known to contain elevated levels of Ba and Sr, convincing some operators that the TDS in the flowback water are coming from the Oriskany. Ba and Sr are more commonly associated with carbonates than with clastic rocks like sandstone or shale, but the Oriskany is sandwiched between the Onondaga and Helderberg Limestones (refer back to the quarry photo in Fig. 5), which may be the source of the dissolved Ba and Sr.

A pathway for formation water from the Oriskany Sandstone to get into the Marcellus Shale is not apparent. Some people think the hydraulic fracs extend down to the Oriskany, but the Onondaga Limestone between it and the Marcellus is a formidable frac barrier. Geophysical data show that most Marcellus hydraulic fracs break upward into overlying shales, not downward into the limestone (Fisher, 2010). Perhaps the hydraulic fractures intercept natural fractures that extend upward from the Oriskany and provide flow paths for the brine. Vertical profiles of formation water chemistry across the Appalachian Basin may be needed to fully understand the dissolved solids content of deep brines.

Given the high TDS found in the produced water, the brines that do occur in the shale pores must be extremely concentrated. Geochemists at the USGS (Rowan et al., 2015) and elsewhere have been investigating the concentration profiles of various dissolved ions in the produced water. Their results indicate the source of the TDS is liquid brines, not solid mineral crystals of salt in the shale pores that are dissolving in the frac fluid. Because different salt crystals have different solubility in water, the ratio of chlorine to bromine, for example, should change over time as one type of salt crystal dissolves faster than the other. These ratios are essentially constant in the produced water through time, indicating that the ions were already in solution before the frac fluid ever got there. Researchers at the University of Pittsburgh have shown that the $^{87}Sr/^{86}Sr$ isotopic ratio is unique enough that it can be used as a "fingerprint" to positively identify Marcellus Shale produced water in the environment (Chapman et al., 2012).

Naturally Occurring Radioactive Material

The geochemical conditions that preserve organic carbon and sulfide minerals in black shale also favor the precipitation of naturally occurring radioactive material, or "NORM." This consists of radioactive elements like uranium, thorium, potassium, and radium that were deposited with the shale. Because of the link between organic carbon and radioactive materials, shale intervals that contain the highest organic content, and therefore the most natural gas, are also the most radioactive. Horizontal boreholes are typically drilled through the most organic-rich, blackest, gassiest, and "hottest" layers of the Marcellus Shale. As such, there are concerns about the levels of NORM in both the drill cuttings from these black shales, and the produced water. NORM in the cuttings is primarily uranium, present in the Marcellus Shale as tiny grains of uranium oxide (Fortson, 2012). The NORM of concern in produced water is radium, which is fairly mobile in solution (Rowan et al., 2011).

The alternating black and gray shales in the Devonian section of the Appalachian Basin can be easily distinguished from one another in a drill hole by using a wireline well log that measures gamma radiation. Black shales containing NORM give a much higher response on a gamma radiation log than the gray shales. The presence of organic carbon also lowers the density of the black shales, compared to the more silica-rich gray units, and this can be detected on a wireline density log. This combination of high gamma and low density on wireline well logs has been used for many years to determine the boundaries and thicknesses of the different black shale units (Boyce and Carr, 2010).

No data on radioactive elements in the Marcellus produced water were supplied in the GTI report because the levels of TDS were so high that the relatively tiny amounts of radionuclides could not be detected (Hayes, 2009). Sodium and chloride were present at levels of hundreds of grams per liter, while radium rarely occurs above concentrations of a few micrograms to milligrams per liter. Other testing has reported radioactivity in the produced water above background levels.

Quantifying NORM in produced water has been challenging. Liz Rowan and her colleagues at the USGS (Rowan et al., 2011) used both historical public data and their own analyses on flowback samples to improve the knowledge base on dissolved radium content of produced waters. Marcellus Shale wells in southwestern Pennsylvania typically show flowback radiation levels to be at background, or even lower. Higher radiation levels have been found in produced fluids from Marcellus wells in northern and eastern Pennsylvania, indicating that there may be some regional trends in NORM.

Concerns are often raised that radioactivity in produced water often greatly exceeds drinking water standards. While this is true, no one is actually drinking produced water straight out of shale gas wells. Current practice recycles the produced water into subsequent fracs, and at the end, residual liquid waste is disposed of down deep UIC wells. In the early days of the Marcellus development, however, radionuclides could have been an issue when flowback was run through municipal wastewater treatment plants, and the outfall was returned to streams. Publicly owned treatment works (POTW) focus mainly on suspended solids and do little to remove dissolved solids from the wastewater stream. As such, another town's water intake downstream could have taken in radionuclides. In a few cases, the Pennsylvania DEP has issued site remediation orders to private treatment facilities when the receiving stream exceeded radioactivity standards due to the discharge of NORM from treated oil and gas wastewater.

The USGS analyzed the sediments in streams below the outfalls of POTWs that had formerly treated Marcellus Shale produced waters (Skalak et al., 2014). No significant accumulation of radionuclides or associated alkali earth metals (Ba, Ca, Na, or Sr) were found in the stream sediments, but in areas where brines from conventional oil and gas wells had been used on highways for deicing, accumulations of Ra, Sr, Ca, and Na were found in adjacent soils (Skalak et al., 2014).

Organic compounds are also common in produced waters from Marcellus Shale wells (Orem et al., 2014). These naturally occurring compounds include polycyclic aromatic hydrocarbons (PAHs), heterocyclic compounds, alkyl phenols, aromatic amines, alkyl aromatics (alkyl benzenes, alkyl biphenyls), long-chain fatty acids, and aliphatic hydrocarbons. Returned frac fluid contains additional organic chemicals, including solvents, biocides, and scale inhibitors. Total organic carbon (TOC) in Marcellus Shale produced water is as high as 5500 mg/L (Orem et al., 2014). Concentrations of hydraulic fracturing chemicals and TOC fall off rapidly within the first 20 d of production and water recovery, although a residual level of dissolved organic compounds may be present for up to 250 d after hydraulic fracturing.

Produced fluids are not the only sources for NORM and organic materials. Long lateral wells drilled through black shale create large quantities (hundreds of tons) of fresh black shale drill cuttings that are often left on the surface. These materials may oxidize and weather over time, leaching toxic compounds and radionuclides into the groundwater for years.

Table 1 presents some analyses on a time series of produced water samples obtained from a Marcellus Shale well. The data were collected on a project at West Virginia University a number of years ago that was investigating methods for cleaning up produced water to recycle it as frac fluid. This has now become standard practice on Marcellus Shale gas wells.

The samples in Table 1 were collected immediately after completion of the gas well, 12 d after completion, 40 d after

TABLE 1. TIME-SERIES FLOWBACK ANALYSIS, MARCELLUS SHALE WELL

		Sample 1	Sample 2	Sample 3	Sample 4	Detection limit
		Date				
Variable	Units	1/20/2010	2/1/2010	3/1/2010	5/13/2010	
pH	pH	7.60	6.07	6.42	6.28	
Conductivity	μS/cm	23,655	16,807	44,610	190,100	
Specific gravity	g/cm^3		1.01	1.03		
SO_4	mg/L	98.80	71.26	47.90		
S	mg/L	8.14	43.33	26.69		0.100
COD	mg/L	1128	1851			
Total Fe	mg/L	37.40	26.72	25.20		0.100
Dissolved Fe	mg/L	29.34	15.29	21.54		0.100
Total Ca	mg/L	319	1,749	1382		0.100
Dissolved Ca	mg/L	289	1607	1316		0.100
Total Mg	mg/L	30.50	121.92	159.14		0.100
Dissolved Mg	mg/L	24.42	105.14	121.58		0.100
Total Na	g/L	3.55	2.86	7.70		0.100
Dissolved Na	g/L	3.37	2.48	7.70		0.100
K	mg/L		56.89	164.83		0.100
Sr	mg/L	<0.011	<0.011	439.49		0.011
Dissolved Sr	mg/L			30.68		0.012
Ba	mg/L	27.15	0.32	204.87		0.011
Dissolved Ba	mg/L			14.23		0.012
Cl	g/L	6.58	7.17	13.64		0.440
TSS	mg/L	44	220	40	74	2.37
TDS	g/L	8.80	12.61	33.80	185.51	3.40
Hardness		923	4870	4107		
Radioactivity						
α background	CPM	ND	ND			
α	CPM	ND	ND			
β background	CPM	51	32	72		
β	CPM	49	38	53		
γ background	CPM	424		449		
γ	CPM	406		420		

Note: COD—chemical oxygen demand; Cl—chloride; TSS—total suspended solids; TDS—total dissolved solids; CPM—counts per minute; ND—not detected.

completion, and 112 d after completion to determine if the composition of the produced water changed over time. Conductivity is reported as microsiemens per centimeter, abbreviated µS/cm. Higher conductivity means the water has more dissolved solids (i.e., conductive ions) to carry electrons.

Using conductivity as an indication of TDS concentrations in the produced water, Table 1 shows a rather dramatic rise between the day 40 and day 112 samples. Fresh drinking water typically has a conductivity of less than 100 µS/cm, and the brackish water found in an estuary may be ~27,000 µS/cm. Seawater has a normal conductivity of ~54,000 µS/cm. Sample #4 in Table 1 has a conductivity of 190,100 µS/cm, or more than 3.5 times that of seawater. The actual values for TDS, sodium (Na), and chlorine (Cl) are reported in grams per liter, not in the more conventional units of milligrams per liter, providing another indication that this water was extremely salty.

The total suspended solids (TSS) content in Table 1 peaked about 2 wk after the flowback began, suggesting that most of the fine materials had been flushed out of the well. The trends for Ba and Sr show little change between the first two samples, but then they climb steeply in the third. Concentration of potassium (K) also rose significantly in the third sample. Geochemists at the USGS and the University of Pittsburgh have found similar variations of Ba and Sr concentrations in other flowback samples. An overall trend of gradually increasing concentrations over time contains occasional rapid concentration increases or "spikes" that then drop back to the original trend. Determining how and when these various ions were entrained in the produced water could be an important clue to the origin of the dissolved solids.

Radioactivity of the flowback water shown on Table 1 was measured for alpha (α), beta (β), and gamma (γ) radiation in values of counts per minute (CPM). Because radiation occurs naturally in the environment, measurements must be compared against background levels. The β and γ radiation values do not exceed background within the range of measurement error. Alpha radiation is easily blocked and difficult to measure in water samples; the values are given as "nondetects," or ND. The radioactivity data do not show any discernible trend over time like some of the other parameters.

The chemical oxygen demand on Table 1 measures the redox potential, i.e., how much oxygen would be required to oxidize the reduced ions brought up from depth. The Marcellus Shale was deposited in anoxic bottom waters; in addition to preserving organic materials, the lack of oxygen also prevented any dissolved ions in the water, such as iron, from oxidizing. Instead, reduced iron precipitated in these euxinic shales as iron sulfide (FeS_2), laminated between layers of organic-rich, black mudrock (Figure 26). Iron sulfide commonly forms the mineral pyrite (also known as fool's gold) and the related mineral marcasite. Both of these will oxidize in air to iron oxide (rust), and sulfate, or SO_4. A familiar sulfate mineral is calcium sulfate ($CaSO_4$) or gypsum, which is used in plaster and drywall. Another sulfate compound is hydrogen sulfate, or H_2SO_4, which is better known as sulfuric acid. Sulfide minerals oxidizing into sulfuric acid in groundwater are the main cause of acid mine drainage in coal-mining regions.

NATURAL FRACTURES AND EMERGING TECHNOLOGIES

Natural fractures in low-permeability rocks like the Marcellus Shale are required for economical rates of gas production. The permeability of the rock matrix itself is far too low for significant amounts of gas to flow from just the surface area of rock in contact with the borehole. As mentioned earlier, typical nanodarcy gas shale is a million times less permeable than a millidarcy conventional gas reservoir. A Marcellus well and the hydraulic fractures must connect with existing natural fractures that provide high-permeability flow paths into a large volume of rock (Carter et al., 2011).

The hydraulic fracturing process opens and extends some existing fractures, creates new fractures, and causes blocks of rock to slide past one another slightly. This changes the distribution of open space in the formation, which must be accommodated elsewhere—occasionally by compression of the rock itself, but more often by closing down other, more distant, preexisting natural fractures.

A subspecialty of geology focuses on the origin and structure of fractures in rocks. Many rock types need a natural fracture system to produce oil, gas, and even drinking water, and quite a few details of the geological history of a rock formation can be determined from analysis of the fractures. Cracks in a rock can sometimes be more important than the rock itself.

As mentioned previously, natural fractures come in two basic types: joints, where the walls have simply pulled apart, and faults, where the walls have slid past each other (refer back to

Figure 26. Layers of iron sulfide (mineral name: pyrite, common name: fool's gold) in a sample from the black Union Springs Member of the Marcellus Shale. Scale is in inches at the top and centimeters at the bottom. Photograph is by Daniel J. Soeder.

Fig. 10). The orientation or direction of a fracture is called the strike, and the vertical angle it makes is known as the dip.

Two sets of vertical joints are prominent in the Marcellus Shale, and indeed in all of the Devonian shales of the Appalachian Basin (Engelder and Lash, 2008). The older set is known as the J1 fractures, and they strike 60°–75° east of north, or to the east-northeast (ENE). These early fractures were created parallel to the axis of the Appalachian Basin as it subsided and filled with sediment. Engelder and Lash (2008) stated that gas pressure generated within the shale during early burial exceeded rock strength and created the J1 fractures in a process similar to hydraulic fracturing.

The second set of joints is called J2, which strike 315°–345° from north, or to the northwest (NW). The J2 joints were formed by basin compression during the Allegheny orogeny. The J2 fractures are oriented at more-or-less right angles to the J1 set, and the two together create an orthogonal fracture set responsible for the blocky shapes seen on shale outcrops, as shown in Figure 27. This photo of the Marcellus Shale type section in New York shows J1 joints crossing ENE from left to right, cut by the J2 joints oriented NW into the hillside at right angles.

Reconstruction of fracture formation requires an understanding of geologic history and careful observations of crosscutting relationships to determine the order of events. The alignment of the ridges formed by the Allegheny orogeny indicates that compressive stress from the Laurentia-Gondwana continental collision was directed toward the present-day northwest. The J2 joints are oriented in the direction of this compressive stress. Fractures form in the direction of compression because the walls move apart at right angles from the direction of maximum force.

Figure 27. Marcellus Shale type section outcrop near Marcellus, New York, showing prominent J1 and J2 joint sets. Pick end of rock hammer is pointed north (hammer handle length is 33 cm or 13 in.). The J1 joints, oriented to the ENE, cross the photo from left to right. The J2 joints, oriented to the northwest, cross the photo from top to bottom. Low evening sun angle on a wet outcrop emphasizes the pattern. Photograph is by Daniel J. Soeder.

This is essentially what happens when firewood is split with a wedge—the wedge supplies compression at one end of the log, and the wood splits along the length.

Two additional sets of joints, designated J0 and J3, are also present in the Marcellus Shale (Engelder and Lash, 2008). These are much less prominent than the J1 and J2 joint sets, and they are less important to gas production. The J0 joints are the oldest fractures, striking north-south, and they are thought to have formed from increased overburden stress during the early stages of sedimentary burial. They are only important locally. The J3 joints are the youngest fractures, and they are not widely distributed. These are oriented east-northeast, and they are related to elastic rebound after the thick, heavy ice sheets sitting on the shale during the last ice age melted at the end of the Pleistocene Epoch. They are limited to the northern, glaciated areas of the basin.

Artificially induced hydraulic fractures open up existing fractures and intercept others to provide flow paths for the gas. The J1 fractures are thought to provide better gas conduits, because they are more laterally continuous than the J2 fractures. Horizontal wells in the Marcellus are typically drilled with an orientation to either the southeast or the northwest to cross the northeast strike of the J1 fractures, with the intent of intercepting as many of them as possible.

A hydraulic fracture from the lateral will be oriented in the direction of weakest stress in the rock, which in the Marcellus Shale would be the direction of the J1 fractures. A frac is engineered to force hydraulic fluid to enter and expand the J1 joints that have been intercepted by the lateral. The effectiveness of a frac depends on opening flow paths in a direction perpendicular to the axis of the lateral, with the goal of contacting as much formation volume as possible. The frac also opens and expands the crosscutting J2 set in areas away from the lateral. There is evidence that these two sets of fractures move slightly in a shearing motion as this takes place, which is beneficial to keeping the fractures open. Asperities on the fracture surface are offset by the shearing motion, and they help to prop open the fractures. This reduces the amount of proppant sand needed. Ideally, the end result is a network of orthogonal fractures that drains gas from the rock in an efficient manner (Bruner and Smosna, 2011). However, the process is not without problems.

There is only so much space available underground. Pushing the walls apart on the J1 joints changes the minimum principal stress direction in the Marcellus Shale by imposing a new compressive stress at right angles to the ENE strike of the J1 joints. This compression to the northwest opens up new fractures parallel to the NW strike of the J2 fracture set. This means that hydraulic frac operations often end up initially creating fractures perpendicular to the lateral, but as the fracs extend outward, changes in the underground stress field cause them to change direction and run parallel to the lateral. This is much less efficient for the effective drainage of gas from the rock.

Because of changes in stress field orientation caused by the hydraulic fracturing process, some gas wells must be refractured after time intervals of months to years once the stresses have realigned with the regional stress gradient. A refracture treatment can open up new flow paths perpendicular to the wellbore and produce more gas. However, mobilization and demobilization charges are a significant part of the total cost of a frac job, and bringing a crew back out to re-frac the well can be quite expensive. As such, engineers have designed several other types of fracture treatments that can reduce or avoid the need to re-frac.

One technique being applied on the Marcellus Shale and elsewhere is called a zipper frac. This treatment involves alternately fracturing matched zones in parallel laterals spaced ~300 m (1000 ft) apart in a back-and-forth pattern, stage by stage. The zipper frac technique enables one well to hold frac pressure while the adjacent well is being fracked. The stress pattern set up in the pressured well helps the fractures avoid each other and maximizes the exposure of the frac to new reservoir rock (Halliburton, 2012). When properly designed and executed, this hydraulic fracturing technique can be very effective at opening up a shale gas reservoir between a pair of laterals.

Similar to the zipper frac, a simultaneous frac involves two laterals that are fractured together. Instead of alternating side to side, a simultaneous frac treats matched stages of the two wells at the same time, to both minimize stress interference, and to prevent communication between the fracture fairways (Bruner and Smosna, 2011). Wells treated with this technique reportedly yield a significantly higher initial gas production than individually fractured parallel wells.

Hydraulic fracturing with oil-based fluids in the Marcellus Shale deeply concerns some people as an alarming alternative to stimulating with water. It is important to note up front that the EPA signed a voluntary agreement in 2003 with BJ Services, Halliburton, and Schlumberger, three of the largest oilfield service companies performing hydraulic fractures, to NOT use diesel-based frac fluid. This agreement does not prevent the use of oil-based muds and fluids for drilling, which some people have confused with oil-based hydraulic fracturing. Some operators did subsequently experiment with diesel-range petroleum additives for hydraulic fracturing, leading to EPA's issuance of guidance (Guidance #84; see U.S. EPA Office of Water, 2014) to more explicitly define the term "diesel fuels."

The original hydraulic fracturing process invented in 1947 by Floyd Farris of Stanolind Oil and Gas Corporation in the Hugoton gas field of Kansas did use crude oil and naphtha gels as the working fluids (Montgomery and Smith, 2010). The water-based frac was a more recent development, having been invented several years later. The only real advantage for using light oil, such as diesel fuel or kerosene, in a hydraulic fracturing operation is that if the target rock is preferentially water-wet, the oil will create fractures without infiltrating into the pore system and potentially plugging it up.

While this may be effective on certain water-bearing formations, the core analysis at IGT (Soeder, 1988) demonstrated that some and perhaps most of the Devonian black shales of the Appalachian Basin are preferentially oil wet (refer back to Figs. 15 and 16). Using an oil-based liquid as a frac fluid would most likely result in a plugged well. In fact, an experimental frac using kerosene was tried on a Devonian shale well during the EGSP (Horton, 1981), with nearly disastrous results. The kerosene plugged up the pores of the shale to the point where it produced essentially zero gas flow, and the cleanup process was described in the report as "difficult."

Some other emerging technologies being applied to the Marcellus Shale include gas fracs, foam fracs, cryogenic fracs, and energy fracs. Reservoir stimulations using pressurized gas—carbon dioxide and nitrogen—instead of water were tried experimentally on Devonian shale during the EGSP (Horton, 1981). The advantages of gas fracturing include easier cleanup and less formation damage, especially on formations like tight gas sand that are preferentially water-wet. Disadvantages include a much higher cost, less effectiveness at initiating and growing the fracture, difficulty entraining and transporting the proppant, and a greater difficulty in controlling the growth of the fracture. For a shale like the Marcellus, which does not appear to be especially sensitive to water plugging-up pores, hydraulic fracturing is simply more economical and effective. Gas fracturing is used occasionally on the Marcellus for specific, specialized stimulations, but it is far less common than water-based hydraulic fracturing.

Foam fracs are a variation on a gas frac, where pressurized gas, usually nitrogen, is mixed with a liquid surfactant to create a high-pressure foam-like material capable of cracking the rock and carrying proppant into a fracture. The foam itself is designed to break down when pressure is released, leaving behind a residual amount of material to help prop open the fracture and allow the nitrogen to escape from the well. Although they work well on shale, foam fracs are costly and used only in special circumstances.

Cryogenic fracs are a compromise between liquid and gas fracs, with the hope of having the best of both worlds. These were also tried during the EGSP, with limited success (Horton, 1981). The idea is to use the gas in liquid form as a hydraulic fluid to crack the rock and carry the proppant into the fractures. The gas then vaporizes, aiding in cleanup. Cryogenic liquid gases are quite expensive, and introducing such intensely cold fluids into the downhole environment can cause all sorts of problems. Steel casing may contract, become brittle, and possibly split, cement may fracture or become unbonded from the casing, and the expansion of ice as residual pore water freezes can cause formation damage near the wellbore. Liquid nitrogen, liquid carbon dioxide, and liquid methane were all tried during the EGSP. Except for methane, these gases must be removed from the produced natural gas before it can be sold to a pipeline, further increasing the expense. The economics are improved if the separated gas can be reused in a subsequent stimulation.

Service companies today offer stimulations using gases that liquefy at higher, noncryogenic temperatures, such as propane and butane, with better results. These gases must still be recovered at the production wellhead before the natural gas can be placed into a pipeline, but the economics are better because cryogenic handling is not needed. Gas fracs are still more expensive than the same-sized hydraulic frac, however, and so are generally used only in special circumstances.

Energy fracs use chemical explosives to pressurize the rock, and they are the oldest type of well-stimulation technology. Before hydraulic fracturing was invented in 1947, the typical method used for stimulating a well was to drop a lit stick of dynamite downhole, or use nitroglycerine. High explosives transmit too much energy too quickly, and tend to thoroughly shatter the rock close to the wellbore without creating the long permeable fractures into a reservoir desired for stimulation, often resulting in more formation damage than anything else. Modern energy fracs use a slower-release explosive such as solid rocket propellant to achieve breakdown pressures in the rock without causing the kind of formation damage that results from high-explosive shock waves. This type of energy frac is called tailored pulse loading, and service companies continue to experiment with them.

Hydraulic fracturing is only used on formations at depths where the stress gradient will produce vertical fractures (King, 2012). This is generally considered to be greater than 2500 ft or 775 m, and it applies to both vertical and horizontal wells. If a rock is too shallow, the low overburden pressure will result in a hydraulic fracture that breaks horizontally, or "pancakes," and does not contact the multiple layers that make up a typical shale reservoir. Sufficient overburden from the weight of the rocks above will prevent this, producing instead a much more efficient vertical fracture. This is because the rocks break in the direction of least stress, and when there is a lot of overburden, the least stress direction is horizontal. The rock splits from side to side, resulting in a vertical crack.

An alternative completion technique for formations too shallow to fracture is to drill them in a branched or "pinnate" pattern of side laterals off a main lateral resembling the structure of a feather (Long and Soeder, 2011). The multiple branched laterals can have a combined length of up to 4.5 km (15,000 ft) total. Pinnate drilling often uses a "coiled tubing" rig, which employs a flexible hose coiled on a drum to supply mud under hydraulic pressure to a steerable bottomhole assembly (Long and Soeder, 2011). The flexible hose allows for much tighter turns than steel drill pipe, but they are more limited in depth.

SHALE GAS RESOURCES

One of the most striking things about the Marcellus Shale and other shale gas resources is the huge amounts of hydrocarbons they contain. Gas resource estimates are built on a number of assumptions about the geology, gas-generating potential, gas in place, and recoverable gas (Charpentier and Cook, 2011). As such, the uncertainty in the estimates is quite high, and the numbers are usually presented in a range ranked by probability. The USGS estimate for the Marcellus Shale gives a 95% probability that at least 43 TCF of gas will be recoverable, a 50% probability that 79 TCF will be recoverable, and a 5% probability of recovering 144 TCF. The mean for the Marcellus is 84 TCF of recoverable gas (Coleman et al., 2011). More recent refinements of the method with additional data have revised the upper end value for the Marcellus to as high as 367 TCF (Milici and Swezey, 2015).

More optimistic calculations done earlier by Engelder (2009) came up with an estimate that the Marcellus Shale has a 90% probability of yielding at least 221 TCF of gas, a 50% probability of yielding 489 TCF, and a 10% probability of yielding 867 TCF, assuming a power-law decline rate, 80 acre (0.32 km^2) well spacing, and 50 yr well life. Initial estimates for Marcellus Shale recoverable gas from the EIA were ~410 TCF (U.S. EIA, 2011), although the EIA has since reduced their estimates to around 144 TCF to be in line with the high-end numbers that came from the USGS in 2011. No matter how it is estimated, there is no doubt that the Marcellus Shale contains large quantities of natural gas.

When the quality or grade of most natural resources is plotted against the quantity, a triangle shape typically results (Figure 28). This is because the highest grade of any resource usually occurs in small amounts, with significantly larger amounts of lower-quality resource. Such a distribution is common for resources like iron ore, coal, gold, timber, diamonds, drinking water, and others. For every perfect one carat diamond, there are hundreds of others that are suitable only for making sandpaper. The ability to exploit a lower-grade resource generally requires higher prices, improved technology, or both (Soeder, 2012).

The large volume of gas present in black shale has been known for some time (Schrider and Wise, 1980). However, the early technology for recovering the gas was costly and only produced limited amounts of the resource. The application of directional drilling and hydraulic fracturing allowed gas to be recovered from shale at prices comparable to conventional reservoirs, and sometimes even cheaper. The Marcellus Shale in particular is located near the big interstate pipelines built to carry gas from the Gulf Coast to cities in the Mid-Atlantic and Northeast. In

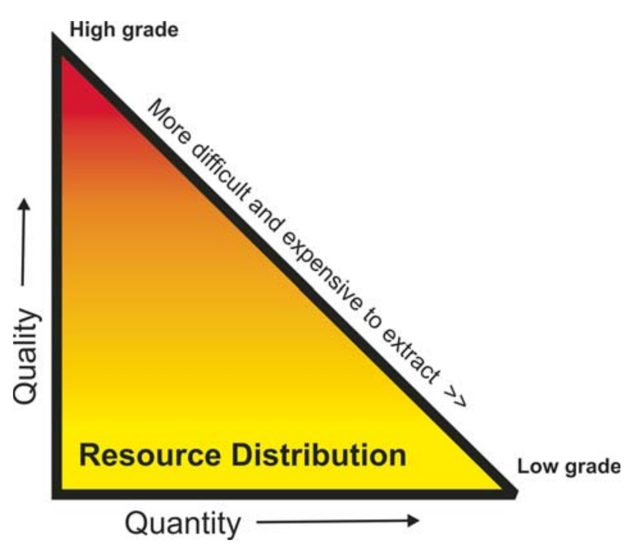

Figure 28. The resource triangle showing the distribution of most natural resources, including natural gas, when quantity is plotted against quality.

southwestern Pennsylvania, where development began, connections were easily made between newly drilled shale gas wells and the major gas transmission lines passing through the area.

Resource Assessment

The amount of gas generated within the Marcellus Shale is assessed from a geological standard called the source-rock quality. This assessment combines data for TOC content, type of organic matter, and thermal maturity, and it gives a rating such as fair, good, excellent, etc. The source-rock quality of the Union Springs Member of the Marcellus Shale (the lower unit; refer back to the quarry exposure shown in Fig. 7) is rated exceptional in southwestern Pennsylvania and northern West Virginia and excellent in western New York, western Pennsylvania, eastern Ohio, and western West Virginia (Bruner and Smosna, 2011). The source-rock quality of the upper Marcellus unit, the Oatka Creek Member, is rated exceptional in northwestern West Virginia and southeastern Ohio and excellent in west-central Ohio and southwestern Pennsylvania. The presence or absence of conditions favorable for the transformation of this organic matter into gas, such as burial history and thermal maturity, is called the relative gas potential of the rock. A rock may have excellent source-rock quality, but if it has not been properly "cooked," it will have a low relative gas potential and not be very productive.

The gas content of the rock is known as gas-in-place (GIP). GIP is calculated from the geographic extent and stratigraphic thickness of the rock unit, combined with a value derived from the source-rock quality and relative gas potential. There are a number of assumptions built into such calculations, and the results can vary widely. GIP in the United States is expressed as billions of cubic feet of gas per square mile, and as trillions of cubic feet for the entire resource (Bruner and Smosna, 2011). Metric equivalents would be millions of cubic meters per square kilometer, and billions of cubic meters.

An early estimate for the GIP value of the Marcellus Shale was derived from the geochemical analyses done by the Monsanto Mound Laboratory in Ohio on the EGSP core (Zielinski and McIver, 1982). The Mound Lab estimate of 178 TCF for GIP is much lower than modern estimates. This is due in part to a smaller study area, which excluded parts of southern New York and northeastern Pennsylvania, and also because only a dozen of the 34 Appalachian Basin EGSP cores reached the Marcellus Shale or equivalents (these are NY-4, OH-1, OH-4, OH-7, OH-8, PA-1, PA-2, PA-3, PA-4, PA-5, WV-6, and WV-7; see Fig. 12 map for locations). Other resource assessments of the Marcellus have been done periodically over the years as more data became available (for example, see Kuuskraa and Wicks, 1984; or Charpentier et al., 1993).

The wide range of estimates for GIP in the Marcellus and other U.S. domestic gas shales is a clear sign that a better understanding is needed of how gas is generated in the shale, and where it resides. Little is known about the basic petrophysics of gas and liquid movement from shale pores into fractures, and from there to a well.

Because shale pores are so small, interactions with pore fluids must be understood at the molecular level (Rodriguez et al., 2014). The nanometer-size pores in shale are approaching the scale of individual gas molecules, where phenomena like gas slippage are not well understood. Diffusion is probably a more important component of gas migration through shale pores than laminar flow. Significant amounts of gas are held in shale by adsorption, presumably on organic matter, but clays may also be important, as shown by adsorption studies on organic-lean shales (Busch et al., 2009). More knowledge about these processes would help to reduce the uncertainty in the assumptions used in the various estimates. Less uncertainty would lead to more constrained numbers and provide more accurate estimates of GIP.

The amount of recoverable gas is always some fraction of the GIP, under the assumption that 100% of the gas will never be recovered, even under the best of circumstances. Hydraulic fractures do not contact every part of the formation; some pores may be blocked with water or oil, and others may not be connected to flow paths. The value for this recovery fraction varies from assessment to assessment. Engelder and Lash (2008) assumed a technically recoverable gas fraction of 10% from a Marcellus Shale GIP resource of ~500 TCF. A subsequent assessment by Clarkson (2013) reported an expected recovery of 40% to 60% of the total gas in place from shale reservoirs over a well lifetime of 10–25 yr.

Why does the Marcellus Shale contain so much gas? 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 the shallow Appalachian Sea during the time of Marcellus Shale deposition. Wrightstone (2011) suggested that the planktonic or floating marine plants were fertilized regularly by dust blown into the basin by trade winds off the arid Acadian Highland areas to the east, which would have added a host of mineral nutrients to the water column in the enclosed Appalachian Basin, including iron and phosphorous. Iron is a fertilizer for algae and has, in fact, been proposed as an additive to seawater for creating oceanic algal blooms that may help remove excess carbon dioxide greenhouse gas from the atmosphere (Powell, 2008).

Wrightstone (2011) described explosions of plant growth in the Appalachian Sea from the periodic fertilization by dust-blown minerals as "bloomin' algae" (Figure 29). He cited documentation from a modern algae bloom that occurred in the Tasman Sea after an epic Australian dust storm in 2009, and similar algal 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 appears to be small particles of quartz that are just the right size to be carried by the wind. Minerals from windblown Tioga volcanic ash might also have fertilized algae.

From a sedimentology standpoint, gas-productive black shales appear to have required low rates of sedimentation

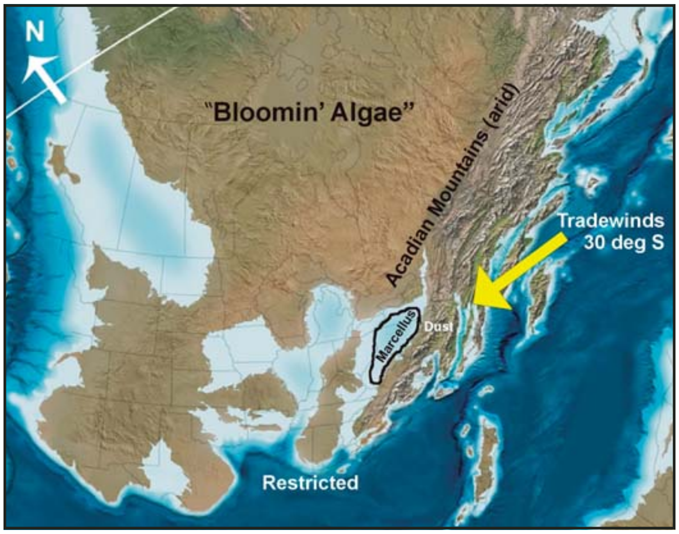

Figure 29. Illustration of "bloomin' algae" in the Appalachian Basin during Marcellus Shale deposition. Trade winds at 30°S latitude would have picked up mineral-rich dust from the arid Acadian Mountains and deposited it in the Appalachian Sea, where it fertilized the algae that supplied organic matter to the Marcellus Shale. Base map is from Blakey (2011), modified after Wrightstone (2011). Outlines of states suggest approximate scale.

combined with significant organic input (Smith and Leone, 2010). Too much sediment would have diluted the organic material and made the shale leaner. Sparser amounts of mineral sediment would allow organic matter to concentrate, generating more hydrocarbons.

Algal blooms create organic matter in the water column, which then migrates to the ocean bottom when the plants die and sink. This sedimentary organic material is known as sapropel. During the time of Marcellus Shale deposition, the enclosed, restricted Appalachian Basin would have had limited water circulation, similar to the modern Chesapeake Bay. Nutrient inputs to the Chesapeake from agricultural runoff or inadequate sewage treatment result in algal blooms. When the algae die and sink to the bottom, decay bacteria rapidly remove residual oxygen from the bottom waters and create anoxic conditions that preserve the organic material. Similar conditions may have helped preserve organic material in the Marcellus Shale.

Other Shales

In terms of total natural gas resources for the United States, the Marcellus Shale is important, but by no means the only player. Development of the Barnett Shale in the Fort Worth Basin of Texas, the Fayetteville Shale in Arkansas, and the Haynesville Shale in Louisiana all pre-date the Marcellus play, and all are still producing.

As gas prices dropped from an oversupply caused by shale gas production, exploration and production companies turned their attention to liquids-rich shale plays such as the Eagle Ford in Texas, the Niobrara in Colorado, and the Utica in Ohio. The natural gas liquids in these formations are produced in the vapor phase, and they accompany the natural gas production out of the well. They condense to liquids under reduced temperatures at the surface, hence their name "condensate." Operators in liquid-rich plays typically have gas-processing plants near production wells to remove condensate such as ethane, butane, propane, hexane, and others, which are worth significantly more money than dry gas. Liquids can also be transported more easily than natural gas, which is mostly limited to pipelines. The Marcellus is known primarily as a dry gas producer, because thermal maturity is too high to have retained many natural gas liquids. However, the far western part of the play near the Ohio River produces the condensate ethane, an important component of polyethylene plastic, and many operators have focused here.

One of the problems with producing natural gas liquids from shale is known as "retrograde condensate." The natural gas liquids exist in a vapor phase under initial reservoir pressures and temperatures. If reservoir pressure management techniques are not applied during production, changes in downhole temperature conditions may cause the vapors to condense into liquid form while still within the shale, resulting in the two-phase flow problem documented by IGT in the Huron Shale (refer back to Fig. 15). Producing both gas and liquid phases simultaneously from the tiny pore spaces and flow paths in shale without losing permeability is a major engineering challenge.

The best-known liquids-producing shales in the United States are the Mississippian-age Bakken Shale and the Three Forks Formation beneath it in the Williston Basin of North Dakota, where the liquids production is light crude oil. The production from this so-called "tight oil" play is different than in more typical gas shales. The Bakken consists of an upper and lower black shale unit, and oil is most often produced from horizontal wells in a middle, unnamed limestone member between the two shales (LeFever et al., 2013). The oil is a very light crude, similar to home heating oil, and there are only a few U.S. refineries that can handle it. Most of these are located on the Gulf Coast, and the issues revolving around the movement of Bakken oil from the northern Great Plains to the Gulf Coast via truck, railroad, or pipeline have been contentious on many levels.

Recent USGS assessments suggest that the Bakken–Three Forks may have recoverable reserves of 7.5 billion barrels of oil, and 6.7 TCF of natural gas (Gaswirth and Marra, 2015). North Dakota lacks much of the infrastructure required for handling the natural gas associated with oil production, and until recently, operators were flaring it off, making parts of the North Dakota prairie appear in aerial and satellite views as brilliant as a large city at night. Such gas is now commonly being re-injected into the ground to maintain reservoir pressures and await the arrival of transmission pipelines. The prolific Bakken–Three Forks has made North Dakota the second largest oil-producing state in the nation, behind only Texas (U.S. EIA, 2014).

Texas is still ahead of North Dakota in oil production because of the Late Cretaceous–age Eagle Ford Shale, which is also a tight oil play, although it produces dry gas in the higher-thermal-maturity areas. The Eagle Ford extends south along the Gulf Coast into Mexico. The Mexican national oil company, PEMEX, was initially reluctant to get aboard the shale development bandwagon, but after observing significant production in Texas, they are showing interest in the Eagle Ford and other shales.

It is worth briefly mentioning production from the Utica Shale, a Middle Ordovician (470 Ma) black shale (Figure 30) in the Appalachian Basin that underlies the Marcellus in many areas (Ryder et al., 1992). This superposition allows for "dual-completion" wells, wherein two target formations are produced from a single borehole. The economics for this are extremely favorable, and a number of companies have been producing two or more shales from such "stacked plays." The Utica extends farther into the northern, western, and eastern reaches of the basin than the Marcellus, and in eastern New York near the Hudson River, it fills buried grabens to thicknesses of up to 600 m (2000 ft). In Ohio, the Utica Shale extends westward from the Pennsylvania border to nearly the center of the state (Ohio Department of Natural Resources, 2017).

The liquids-rich production area of the Utica Shale is in southeastern Ohio. Although the formation tends to have more carbonate and a lower organic content than the Marcellus, it is also deeper and thicker. The initial production (IP) from several Utica wells in Ohio has been astonishing, significantly exceeding Marcellus IP numbers in southwestern Pennsylvania. A recent assessment of the hydrocarbon resources in the Utica Shale estimated that ~782 TCF of natural gas and liquids may be recoverable from this formation (Hohn et al., 2015). Compared to the mean of 84 TCF of recoverable gas assessed in the Marcellus by the USGS (Coleman et al., 2011), or even the more optimistic estimates by Engelder (2009) of 489 TCF of Marcellus gas, 782 TCF is significant.

Figure 30. The Flat Creek Member of the black Utica Shale exposed at Flat Creek, New York. Bluff is approximately 30 m (100 ft) high. Photograph is by Daniel J. Soeder.

Other shales of interest in the United States include the Rhinestreet and Ohio Shales in the Appalachian Basin above the Marcellus, generally referred to as "Upper Devonian" by the drilling companies. These shales could also be tapped by dual-completion wells. In fact, the stratigraphy at a few localities contains the Upper Devonian section above the Marcellus, and the Utica below the Marcellus, suggesting a possibility where all three shale targets could be completed.

Alabama is investigating possibilities with the Floyd Shale and the Conasauga Shale. Other well-known, organic-rich shales like the Antrim in the Michigan Basin, the New Albany in the Illinois Basin, and others are being explored for their gas potential. In Utah, the Mancos, Manning Canyon, Paradox, and Pierre-Niobrara Shales have gas potential. The Niobrara has undergone significant development in the Denver-Julesburg Basin in Colorado and in places in Wyoming. It is also being assessed as a small producer in South Dakota (Soeder et al., 2015).

A potentially useful by-product of increased natural gas production could be an increase in the supply of helium. Most commercial helium is produced by the natural radioactive decay of elements inside Earth, and it becomes trapped with natural gas. Traditional production of this important element from conventional natural gas fields in Kansas, Oklahoma, and Texas has declined in recent decades, even as demand has risen. Cryogenic uses of liquid helium, and increased helium use in U.S. Homeland Security screening devices have caused prices to skyrocket. Helium contents in shale gas are typically low, but with improved separation technology, greater overall gas production, and high helium prices, there is a potential to develop new supplies.

RESOURCE DEVELOPMENT

The development of domestic shale gas stems from the so-called "energy crises" of the 1970s caused by the embargo of oil exports to the United States. The U.S. DOE crafted a solution to these disruptions by broadening domestic energy production across a mix of natural resources. The Obama Administration has called this an "all of the above" energy strategy, where the idea was to lessen dependence on a single supply. Shale gas was one of these "all of the above" resources, and the persistence of people like George P. Mitchell carried it forward.

Is the "energy crisis" still a valid concern in the twenty-first century? Do we really need domestic energy production in the

United States? One major difference from the 1970s is that the United States now faces strong competition for world oil supplies from developing industrial countries such as China and India. Future supply disruptions of imported oil may be due more to economics than politics. Foreign oil producers could choose to sell their product to any country willing to pay the highest prices, and that might not be the United States. Secure domestic energy supplies are still important.

The extensive development of shale gas and oil in the decade between 2010 and 2020 has significantly changed energy economics in America and the world. Traditional pathways for the movement of energy, from the U.S. Gulf Coast to the Northeast, from Alaska to California, from the Middle East to Europe and the U.S. East Coast, have all changed. Some U.S. pipelines have reversed flow, moving natural gas liquids from Appalachia to Gulf Coast refineries. Liquefied natural gas (LNG) import terminals on the U.S. East Coast are being reconfigured for exports. With the recent loosening of export restrictions imposed in 1975, oil from the Bakken Shale is being exported to China and Japan.

It is not just changes in the location of the fossil energy production that are disruptive. Abundant natural gas from shale is displacing other forms of fossil energy such as coal (Culver and Hong, 2016). This has devastated regional, coal-based economies in places like Appalachia, but it has also produced significant environmental benefits by reducing overall U.S. carbon dioxide emissions. However, the environmental advantages of gas must be weighed against the disruptions caused to vulnerable populations by changing energy economics. Some in southern West Virginia would argue that the environmental benefits of turning away from coal are not worth the cost.

There is no doubt that natural gas is a relatively clean and efficient fuel compared to other fossil energy sources. It is lower than both oil and coal in carbon dioxide emissions per thermal unit (Btu), and gas production is far less disruptive to land and water than surface (strip) mining of coal. Likewise, natural gas does not produce any of the hazardous combustion by-products of coal, or the photochemical components of smog like gasoline. Shale gas may not be the ultimate energy solution for the United States, but it is a better alternative at present than any other fossil fuel for the environment.

Figure 31 is a map from the Pennsylvania DEP that shows the locations of nearly 12,000 Marcellus Shale gas-drilling

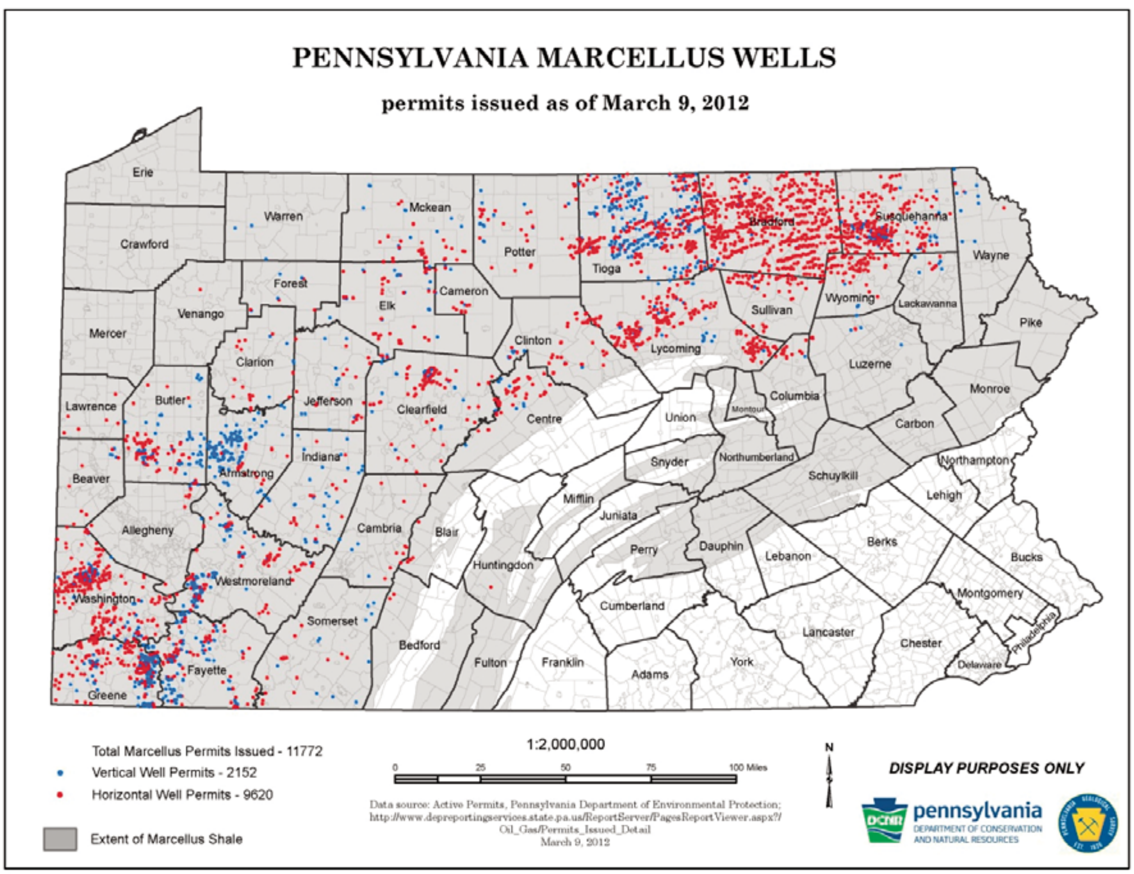

Figure 31. Permit activity for Marcellus Shale wells in Pennsylvania as of March 2012, with counties labeled. Source: Pennsylvania Department of Environmental Protection, 2017. The southwestern corner of Pennsylvania is 39°43′ 17.0″N, 80° 31′ 09.6″W. Map is for display purposes and is not to be used for lease tract identification or navigation.

permits, including >9600 for horizontal wells as of March 2012 (www.depweb.state.pa.us). The date on the map is not important, and the reason for including it was to show a trend. Most of the Marcellus Shale wells are located in either the southwest corner of Pennsylvania, or in the northeastern part of the state.

Southwestern Pennsylvania is where the play began, in Washington County, where Range Resources' discovery well, Gulla #9, was drilled in 2007. The shale is thinner there and not as productive as other parts of the play, but the interstate transmission pipelines run through this area on their way east, and they were able to take in the Marcellus gas. The shale in this location produces both methane gas and the condensate ethane, which is valuable feedstock for making polyethylene plastic. The second most concentrated area for shale gas development is in the northeast corner of Pennsylvania near the New York State line. The well locations here line up along the valley and ridge topography in this part of the folded Appalachians. The Marcellus Shale is thicker and more gas productive than in the southwest, but there are not many pipelines through northeastern Pennsylvania. Many of the permits shown on the map are undrilled leases that are waiting for a pipeline. Marcellus gas production in northeast Pennsylvania is nearly pure methane without profitable condensate, and many operators are waiting for natural gas prices to climb back to profitable levels before spending the capital on a well.

The take-home lesson is that impacts will be the greatest in areas of concentrated drilling, defined by the "sweet spots" in the play. Trying to predict the locations of future impacts requires trying to ascertain where the drillers and their rigs will be going. A continuous gas resource like the Marcellus has many factors besides geology that dictate the locations of future development.

A trend over the past few years has been to establish horizontal Marcellus wells in existing, small gas fields that are producing from conventional reservoirs such as sandstones, stratigraphically either above or below the shale. Such gas fields already have compressor stations, gas-processing plants, and pipeline infrastructure in place, and it is quite economical to hook a Marcellus well into the existing gathering lines. As an added benefit, operators can often use production from the existing gas field to run the generators needed to operate their hydraulic drill rigs, thus saving considerable money on diesel fuel.

When counting wells, it is important to distinguish among leases, permits, drilling, and actual well completions. An assessment of completion reports from state records by Avary and Schmid (2012) determined that 1469 horizontal and 499 vertical Marcellus shale wells had been reported as completed in Pennsylvania, for a total count of 1968. This compares to the 12,000 permits issued as of the same year as shown in Figure 31. In West Virginia, the numbers are 1398 vertical wells and 366 horizontal. This is a total of 3682 Marcellus Shale wells within the play, of which 1835 are horizontal.

In actuality, the number of drilled wells is much higher, because the completion reports lag months to years behind the drilling. Obtaining an accurate count of Marcellus wells is a challenging question that has many researchers stumped. The number in Pennsylvania is somewhere between the 12,000 permits issued and the 1968 completion reports received. Narrowing it down further is anyone's guess, but there may be around 4000 Marcellus wells to date.

Social License

The development of shale gas resources faces a barrier known as a "social license." This means that the community, which is likely to be affected by the noise, dust, lights, congestion, and other inconveniences associated with the shale gas project, must agree that it is worth doing. If operators expect to be met with a permit, rather than a protest, the community has to be convinced that the benefits outweigh the liabilities, and the level of acceptable risk is acknowledged.

Companies generally understand that careless or blatant environmental violations will only result in their losing access to the resource. Having the entire state of New York closed to shale gas drilling has made this point quite clear. As such, many companies recognize the need for community involvement.

Operators often work with township or county road authorities to route truck traffic onto roads that are already slated for repair, and then pay to replace the road after the wells are completed. Most operators avoid moving equipment and materials during the hours when school buses are operating. In some locations, temporary overland pipelines serve to move water around instead of a fleet of trucks.

Other, more direct community support from companies includes donations of parkland and baseball fields to a town, construction of recreation or youth centers, and helping to fund local charities. Operators recognize that these investments in a community are the necessary cost of a social license to do business.

A sociological study on the impacts of Barnett Shale drilling in Texas (Theodori, 2008) found some public perceptions that are applicable to the Marcellus Shale as well. Surveys done in Texas compared counties with a population familiar with the drilling industry (identified as a more mature county) to those that were less familiar with it.

In less mature counties, the social and environmental impacts of the drilling were largely seen as being negative, although the economic and service-related aspects were viewed positively. Negative factors included concerns about increased truck traffic, large volumes of freshwater use, higher tax rates, aquifer depletion, noise pollution, and water pollution. Positive factors included economic development, new jobs, better local police force protection, enhanced fire protection services, improved medical/health services, and financial benefits to schools. The bottom line was that the public tends to distrust the intrusion of the gas industry into a community and resent the environmental issues that accompany it, while at the same time the citizens welcome the economic and service-related benefits.

Tarrant County, which includes the city of Fort Worth, was considered a mature county because of the longer history of

Barnett Shale production. Even here, public perceptions about risks and benefits of drilling were mixed. Theodori (2008) found that social and environmental factors are more likely to elicit a citizen response than an economic factor. In other words, potential water contamination from a frac fluid spill was the talk of the town, but the prospect of funding new schools with drilling taxes did not garner much attention.

Most people who work in the shale gas development industry are sensitive about being associated with those who carry out bad practices. Individuals and companies who follow good practices rightly hold themselves above those who do not, bristle indignantly, and refuse to apologize for "bad operators." Apologies are not needed, but a little more self-policing is. Even though drillers often know of a bad operator, there is a great deal of ingrained reluctance throughout the industry to interfere, or to tell someone "how to run their business." When the issue of self-policing is brought up, the standard answer from industry is that responsible companies will cease commercial interactions with the bad operators and eventually drive them out of business. All well and good, but this process is slow and allows a great deal of collateral damage to be done in the meantime.

At the worker level, firing incompetent, careless, or sloppy employees may solve the problems at one site, but in boom times, when workers are in short supply, these people just go down the road and get another job at the next drill rig, often without even a simple reference check or a phone call to a former employer to slow them down. The industry as a whole needs to do a better job internally at dealing with the bad apples, both the individuals and the companies. If responsible operators took action to call the regulators and stop the bad practices, it would benefit them, their industry, and society in general.

International Resources

Gas and oil production from shales is of interest worldwide. Many countries that have limited conventional hydrocarbon reservoirs are finding gas-and-oil–rich black shales to be a significant resource. Once George Mitchell's ideas about how to horizontally drill and hydraulically fracture these rocks became known, the exploration of shale energy resources intensified nearly everywhere (Figure 32). Shales in Canada, Britain, Germany, Poland, Ukraine, China, India, Australia, South Africa, Argentina, Brazil, and other countries are being investigated for hydrocarbon potential (U.S. Energy Information Administration, 2015a). Estimates for shale gas resources in other countries are often very uncertain because data are sparse. Some Arctic sedimentary basins in Canada, for example, may have gas shales in them, but they are so remote that no one has drilled or explored them yet.

Several European countries are interested in domestic shale gas because of the high cost and political uncertainty inherent in importing natural gas. The day-to-day realities of environmental sensitivities in the Eurozone have made shale gas development much more challenging in Europe, however. France has banned hydraulic fracturing and is pushing for similar measures throughout the European Union.

Other countries are moving forward, albeit slowly. The UK has some potential gas shales in England. The Royal Society

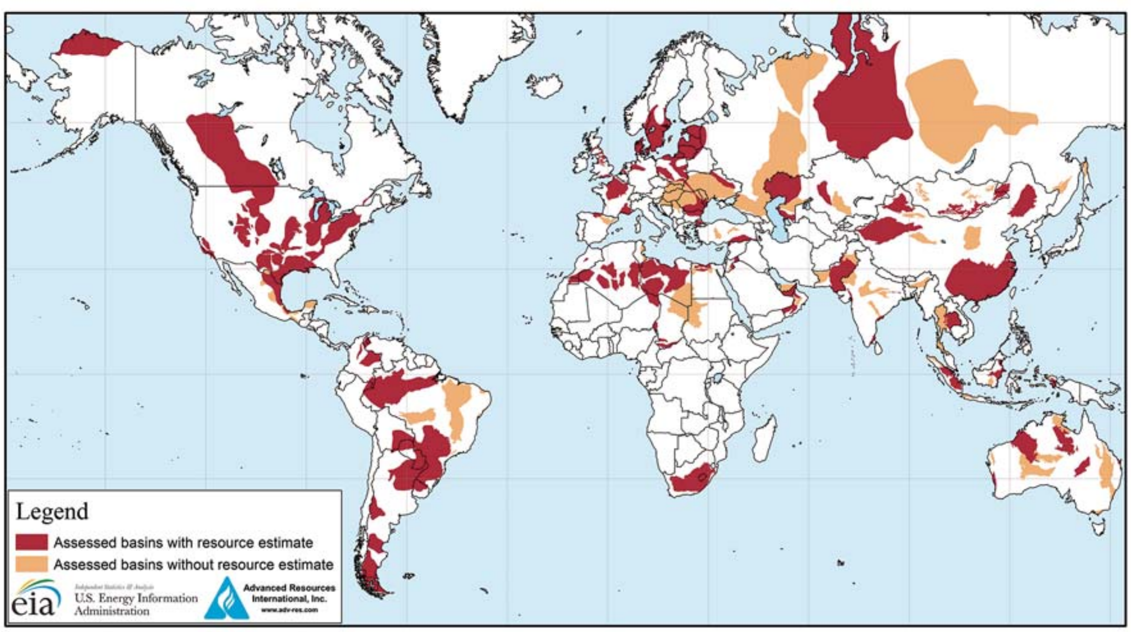

Figure 32. Sedimentary basins worldwide containing assessed shale gas resources. Source: U.S. Energy Information Administration (2015a).

and Royal Academy of Engineering (2012) investigated the technical risks associated with the extraction of shale gas and assessed ways that these can be managed. Germany has also been tentatively investigating potential environmental risks of shale gas development.

Poland is one of the countries trying to move away from a reliance on domestic coal and imported gas, and they are interested in developing domestic natural gas from Silurian black shales. These occur at depths of 3–4 km (~10,000–13,000 ft) in a belt stretching from central Pomerania to the Lublin region (Konieczyńska et al., 2011). The Polish Geological Institute and the Voivodeship Inspectorate for Environmental Protection carried out an environmental impact assessment in 2011 on a shale gas well called Lebien LE-2H (Konieczyńska et al., 2011). This is one of the first such assessments ever done. The Polish scientists collected data on air, water, groundwater, ecosystems, and landscape impacts from the development of the Lebien LE-2H well and concluded that when proper construction techniques were followed, environmental impacts of shale gas drilling were minimal and manageable.

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