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Super FRACKING

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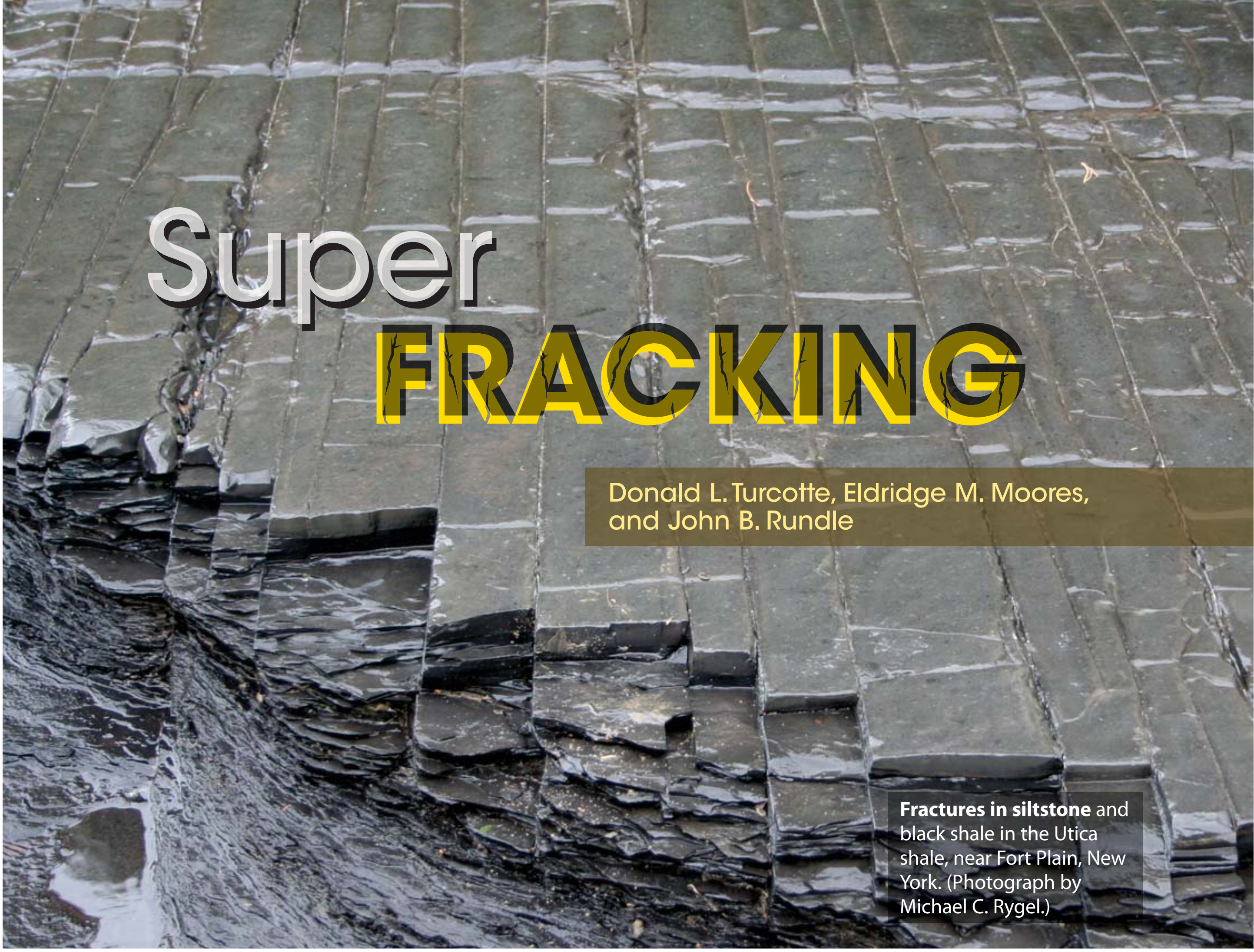


Fractures in siltstone and black shale in the Utica shale, near Fort Plain, New York. (Photograph by Michael C. Rygel.)

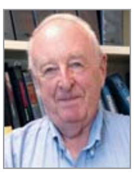
Injecting large volumes of low-viscosity water helps energy producers extract oil and gas from shales that tightly confine those fossil fuels. But the technique also confronts technical and environmental issues.

After rising steadily for decades, US annual production of natural gas peaked at 22.7 trillion cubic feet (Tcf) in 1973. For a decade thereafter, production generally declined as gas reservoirs became depleted. It picked up for a while after that but really took off in 2005; by 2012 natural gas production had risen to 25.3 Tcf.

The rapid increase in the availability of natural gas strongly influenced gas pricing. On 1 January 2000 the wellhead price was $2.60 per thousand cf. By 1 January 2006 the price had increased to $8.00, but by New Year's of 2012 it was down to $2.89. The impressive gas production increases and price decreases over the past decade or so are primarily due to a variety of hydraulic fracturing, or fracking, in which large volumes of low-viscosity water are pumped into low-permeability ("tight") shale formations. We call that type of hydraulic fracturing "super fracking" to distinguish it from long-established hydraulic fracturing with low volumes of high-viscosity water.[1,2]

An important consequence of the drop in natural gas prices over the past several years has been the substitution of natural gas for coal in electric power generation plants. As a result, carbon dioxide emissions from power plants have been reduced by about a factor of two. That said, we do not wish to minimize the environmental concerns associated with high-volume fracking. The box on page 36 spells out some of the issues.

Traditional fracking has been in use for more than 50 years. Super fracking, which, like the traditional kind, is used for oil as well as gas production, is a relative newcomer; it arrived on the scene about 30 years ago and became economically viable around 1997, with profound consequences, as the natural gas numbers cited above show. Although our focus will be on the high-volume variant, we



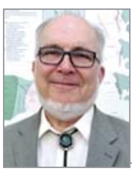


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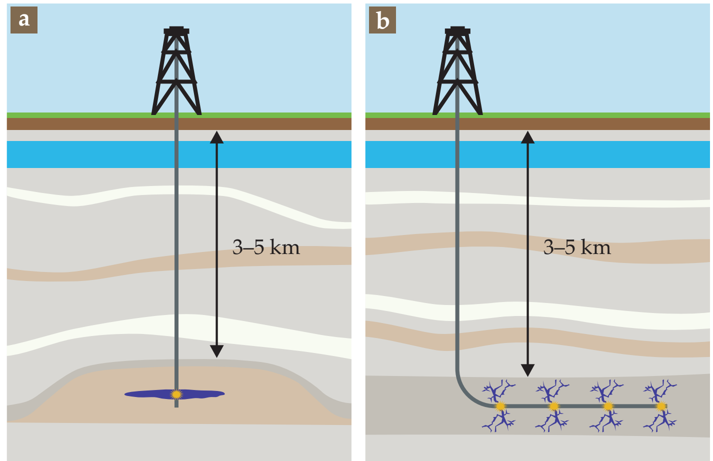
Figure 1. Traditional and high-volume fracking. **(a)** In traditional fracking treatments, a high-viscosity fluid creates a single hydraulic fracture through which oil or gas (or both) migrates to the production well. **(b)** In high-volume fracking, or super fracking, large volumes of a low-viscosity liquid create a wide distribution of hydraulic fractures. Fossil fuels can then migrate through the fracture network to the production well. The sketch here shows the result of a sequence of four high-volume fracking injections. Such sequential injections would not be possible without directional drilling, which creates a horizontal production well in the target stratum.



will also have a few words to say about traditional fracking. But first we turn to an examination of the shales that house oil and gas.

Fossil fuels' underground home

Just as sandstones are a rock equivalent of sand, shales are a rock equivalent of mud. They can extend horizontally for more than a thousand kilometers and have a porosity of 2–20%. The shales that are a main source for hydrocarbons are known as black shales because of their color and organic content. Their pores are typically filled with 2–18% by weight of carbon in organic compounds. A representative grain in a shale is less than 4 μm wide; surface-tension forces due to those fine grains strongly restrict fluid flow.

Black shales form when large volumes of organic matter are deposited in muds beneath the sea. If the organic carbon is to be preserved, the deposition and subsequent burial must occur under anoxic conditions. That is one reason why some 90% of the world's oil originated in well-defined periods encompassing 200 million out of the past 545 million years. The largest known region currently forming organic-rich clays—future black shales—is the Black Sea.

The environment in which sediments are deposited has a thermal gradient of something like 30 °C/km. At sufficient depth, time and heat produce oil from the organic material. That oil is located in a window 2–4 km below the surface where temperatures range from about 60 °C to about 120 °C. At depths of 3–6 km and associated higher temperatures of around 90–180 °C, the oil breaks down to produce gas.[3]

Sedimentary organic material can form oil and gas only under anoxic conditions. Thus the deposition and burial of the organics must occur in an environment with restricted water circulation—otherwise, the water would oxidize the carbon in the sediment. As noted above, the fine grains that form shale enforce that restriction via surface-tension forces.

Natural fracking

Oil and gas formation in black shales increases fluid pressure; the resulting hydraulic forces yield a network of fractures.[4] For that natural fracking to come about, the pore pressure must be about 85% of the pressure generated by the weight of the overlying rock.[5] The main factors responsible for natural fractures and their orientations include tectonic activity and the structure and mineralogy of the shale.

One consequence of natural fracking is a pervasive set of fractures, such as those shown in the opening image. Although the granular permeability in shales is low, it is sufficient to permit oil and gas to flow to the closely spaced fractures, which provide pathways for vertical migration. The upward movement reduces fluid pressure and takes the fossil fuels from their source in the black shale to reservoirs that can be exploited for production, or even to the surface as oil and gas seeps.

An excellent example of the results of natural fracking processes can be seen in the Monterey shale in California, the source rock for major oil fields in the Los Angeles, Ventura, Santa Maria, and San Joaquin sedimentary basins.[6] The northern Santa Barbara Channel, separating the Santa Barbara coast from California's Channel Islands, is one of the largest hydrocarbon seepage areas in the world.[7] Oil and gas leak upward through natural fractures and tectonic faults in the Monterey shale. The most intense area of natural seepage is about 15 km west of Santa Barbara at the Coal Oil Point seep field, where the resulting oil slicks can be as much as 10 km long. Centuries ago the earliest Spanish settlers and English explorers recorded the existence of beach tars in the region.

In some cases, natural fracking has enabled the direct extraction of fossil fuels from tight shale reservoirs. More often, natural fractures and faults allow the migration of oil and gas to high-porosity reservoirs. Once trapped there, the oil and gas can be extracted with traditional production wells. However, the fraction of the oil and gas that is recovered from the production reservoir is low, typically 20–30%.

Energy producers have tried several methods to enhance recovery. One process involves flooding the production reservoir: Water or another fluid introduced at so-called injection wells drives the oil and gas to the production wells. A second process is hydraulic fracturing. As illustrated in figure 1, the technique involves the high-pressure injection of water so as to create fractures in the production

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Environmental concerns

Oil and gas production utilizing high-volume fracking has several associated severe environmental problems.[1] Those include the following:

- The need for large volumes of water. In some areas, fracking significantly reduces the water available for other purposes.
- Contaminated water. The water injected during fracking is subsequently returned to the wellhead adulterated by additives and natural contamination such as radiogenic isotopes from the rock. In many cases, injection wells return that water to a sedimentary layer. Such wastewater disposal creates a number of environmental concerns, including leakage and induced seismicity.
- Leakage of methane gas into the atmosphere. Wells in North Dakota's Bakken shale, for example, produce gas in addition to oil. At present, the site doesn't have enough pipeline to use all the gas extracted, so workers burn off significant quantities of it. That practice, called flaring, is clearly undesirable in terms of air pollution and greenhouse gas production and as a waste of a natural resource. Oil producers on the North Slope in Alaska must reinject gas that cannot be used. Ongoing efforts may lead to a federal requirement for reinjection in North Dakota and other localities.
- Leakage of methane gas or other fluids into shallow aquifers. Documented leakage into shallow layers, including aquifers, appears to be associated with the well casing itself or with the cementing of the well casing to the rock.[1] Leaks of fracking fluid from shale into groundwater are unlikely because the high-volume fracking injections generally occur at depths of a few kilometers—well below groundwater aquifers, which are no deeper than 300 m. However, fracking fluids, flowback waters, and drilling muds have occasionally been spilled on the ground.
- Triggering of damaging earthquakes. As discussed in the main text, high-volume fracking generates numerous small earthquakes, and the possibility of a large earthquake cannot be ruled out. However, the largest earthquake attributed to high-volume fracking had a magnitude of 3.6, which is too small to do surface damage. On the other hand, some larger earthquakes, including a magnitude-5.7 quake that struck Oklahoma in 2011, have been attributed to wastewater injection.[16]

The documented and potential problems associated with super fracking call for regulation by state and federal agencies—and some regulations are already in place. Any regulatory framework, though, must distinguish between traditional and high-volume fracking because the environmental problems discussed in this box are not associated with traditional, low-volume fracking.

reservoir and facilitate migration to the production well. Traditional low-volume fracking enhances production from high-permeability reservoirs. High-volume super fracking is the method of choice for extracting oil and gas from tight shale reservoirs.

Volume and viscosity

Traditional fracking generally requires 75–1000 m^3 of water whose viscosity has been increased by the addition of guar gum or hydroxyethyl cellulose. The objective, as shown in figure 1a, is to create a single large fracture, or perhaps a few of them, through which oil and gas can flow to the production well. A large volume of injected sand or other "proppant" helps keep the fractures open. Energy producers now routinely apply traditional fracking to granular reservoirs, such as sandstones, that have permeabilities of 0.001–0.1 darcy. (The darcy is a measure of fluid flux corrected for the viscosity of the fluid and the pressure gradient driving the flow.) Indeed, analysts Carl Montgomery and Michael Smith estimate that some 80% of the producing wells in the US have been treated with traditional fracking.[8]

The natural permeability of the rock allows oil and gas to migrate to the single open fracture and subsequently make their way to the production well. However, traditional fracking does not successfully increase oil and gas production from tight shale reservoirs in which few fractures exist or in which the natural fractures have over time been sealed by deposition of silica or carbonates.

In tight shale formations, the granular permeability is between 10^{-9} darcy and 10^{-7} darcy, a good six orders of magnitude or so lower than usual for sandstone reservoirs. Super fracking, with its large volumes of water and high flow rates, was developed to extract oil and gas from them. Additives, usually polyacrylamides, decrease the viscosity of the water; the treated fluid is generally called slickwater. Typically super fracking uses 100 times as much water as traditional fracking. The objective of high-volume fracking is to create many open fractures relatively close together—so-called distributed damage.[9] Those fractures allow oil and gas to migrate out of the rock and to the production well. Many of them are reactivated natural fractures that had been previously sealed.

As illustrated in figure 1b, high-volume fracking involves drilling the production well vertically until it reaches the target stratum, which includes the production reservoir. Then directional drilling extends the well horizontally into that target stratum, typically for a distance of 1–2 km. Plugs, called packers in the industry, block off a section of the well, and explosives perforate the well casing. It is desirable to target reservoirs that are 3–5 km deep to ensure that the overlying material can generate enough pressure to drive out the oil and gas.

The slickwater, injected at high pressure through the blocked-off, perforated well, creates distributed hydrofractures. At the end of the fracking injection, the fluid pressure drops and a fraction of the injected fluid flows back out of the well. Then production begins.

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In our view, high-volume fracking is successful only in the absence of significant preexisting fracture permeability. That's because significant fracture permeability would provide pathways along which the injected fluid can flow. The result would be a fluid pressure that is too low to create distributed new fractures. We will return to that idea below, in connection with the Barnett and Monterey shales, but we acknowledge that our conclusion is certainly not universally accepted.

Small earthquakes

High-volume fracking creates a distribution of microseismic events that documents the complex fracture network generated by the fracking. Nowadays something like 10% of production wells are accompanied by one or more vertical monitoring wells that have seismometers distributed along their lengths. Those seismometers can locate microseismic events in real time, and the data they provide can help optimize injection rates.

Figure 2 shows a typical example, from the Barnett shale in Texas.[10] The first two of four injections produced relatively narrow clusters of seismicity, whereas the third and fourth injections produced much broader clusters that indicate a less localized fracture network. A possible explanation for the difference focuses on the role of preexisting natural fractures: The narrow clusters may result from injections into the closely spaced natural fractures, whereas the broad clusters may reflect an extensive new fracturing network needed to access natural fractures.

Typically, the microearthquakes accompanying super fracking would register in the −3 to −2 range on the Gutenberg–Richter scale, much too small to be felt at the surface. But the magnitude distribution of the microearthquakes satisfies the same scaling as tectonic earthquakes: The logarithm of the number of earthquakes with magnitude greater than m varies linearly with m. Thus the possibility of a larger earthquake cannot be ruled out. However, for the microseismicity associated with high-volume fracking, the b value (negative of the slope) is in the 1.5–2.5 range, whereas for tectonic earthquakes it's 0.8–1.2. Extrapolating the linear relation suggests that the probability of a magnitude-4 earthquake arising from super fracking is something like 10^{-15} to 10^{-9}, clearly very small.

We now turn to some specific examples of oil and gas extraction from tight black shales. We first consider the Barnett shale in Texas. The Barnett was the site of the first high-volume fracking injections of slickwater, a technique primarily developed by Mitchell Energy beginning in the late 1980s. We next consider the Bakken shale on the US–Canada border. Unlike the Barnett, the Bakken shale produces primarily oil. We then consider the Monterey shale in California and discuss why high-volume fracking has not been successfully applied there.

Barnett and Bakken

The Barnett shale is a black shale that formed during the Lower Carboniferous period, 323 million–340 million years ago. Figure 3a shows the location of the shale, which is in the Fort Worth basin of Texas. The organic carbon concentrations in the productive Barnett shale range from less than 0.5% by weight to more than 6%, with an average of 4.5%. Production depths range from about 1.5 km to 2.5 km. The gas-producing stratum has a maximum thickness of about 300 m, is relatively flat, and has only slight tectonic deformations.

Most natural hydraulic fractures in the Barnett shale have been completely sealed by carbonate deposition.[11] The bonding between the carbonate and shale is weak, so a high-volume fracking injection can open the sealed fractures with relative ease.[12] We suggest that once opened, the natural fractures prevent subsequent high-volume fracking injections from creating distributed fractures. Instead, the injected slickwater leaks through the natural fractures without producing further damage.

Until being overtaken by the Marcellus shale in the Appalachian basin, the Barnett shale was the largest producer of tight shale gas in the US. Its annual production of 0.5 Tcf of gas is an appreciable fraction of the total national annual production of some 25 Tcf. In 2011 the US Department of Energy estimated[13] the accessible gas reserves in the Barnett shale to be 43 Tcf.

The Bakken shale is a black shale located in the Williston (also called the Western Canada) basin;

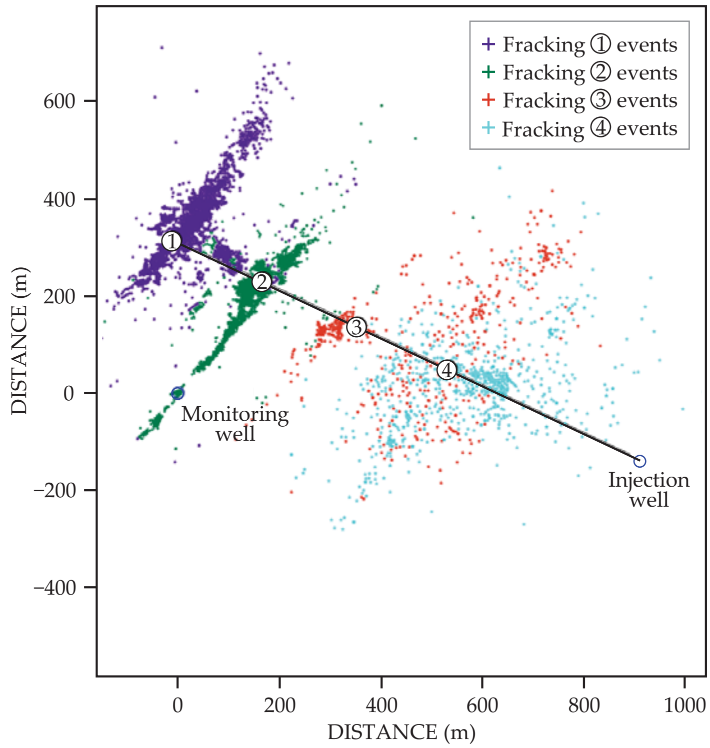

Figure 2. Small earthquakes associated with four high-volume frackings of the Barnett shale in Texas. Each tiny "+" symbol on this microseismicity map shows the epicenter of a microearthquake. Collectively, the symbols reveal the distribution of fractures induced by the injected water. The monitoring well is at the origin of the coordinate system shown. The injection well is off to the right; the thin line shows its horizontal extent. (Adapted from ref. 10.)

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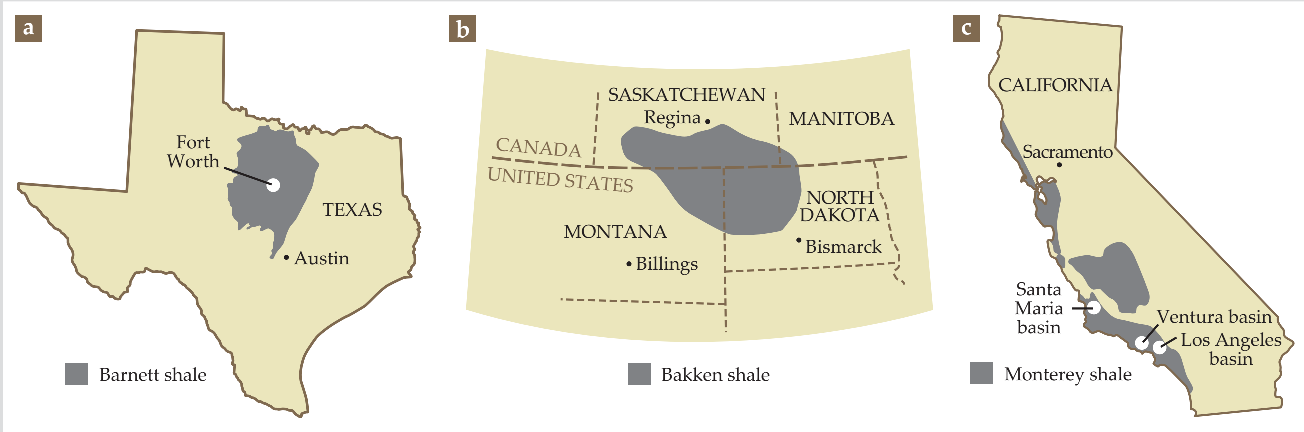

Figure 3. Show me the shale. The three maps here give the locations of important fossil-fuel-producing shales in the US. **(a)** The Barnett shale is in north central Texas. **(b)** The Bakken shale, in the Williston basin, encompasses regions of the US and Canada. **(c)** The Monterey shale extends along much of California. (Maps courtesy of Janice Fong.)

see figure 3b. It formed during the Late Devonian–Lower Mississippian period 340 million–385 million years ago. Unlike the Barnett shale, the Bakken has yielded large amounts of oil. Most of it comes from North Dakota, which now produces more oil than any state but Texas.

The Bakken shale is mostly horizontal and has little tectonic deformation. It consists of two black shale layers separated by a layer of dolomite (calcium magnesium carbonate) and is the first formation in which high-volume fracking demonstrated success at effectively extracting oil from a tight shale. The relative contributions of the black shale layers and the dolomite layer to production are not clear. But it is clear that high-volume fracking is essential for significant oil production at Bakken. The shale typically has 5% porosity, but the bulk permeability is very low, typically 4×10^{-9} darcy. Most natural fractures are tightly sealed, which allows super fracking to create distributed fractures through which oil can migrate to production wells. The producing formation typically is 1.5–2.5 km deep and as much as 40 m thick.

In July 2013 about 6000 producing wells, primarily horizontal, operated in the Bakken shale. They contributed to an annual oil production rate of 300 million barrels (Mbbl), or 4.8×10^7 m^3. Estimates from DOE of the oil reserves in the Bakken shale are 3.6 billion barrels (Bbbl),[13] half again as much as the total US production of 2.37 Bbbl for the year 2012.

Monterey

The Monterey shale in California is a diverse area of organic-rich layers of black shale alternating with silica-rich beds derived principally from rocks and the shells of diatoms. The Monterey shale, much younger than the Barnett and Bakken shales, formed 8 million–17 million years ago during the Miocene epoch. Due to its relative youth, it has not had the time to become a tight black shale with sealed natural fractures. Open natural fractures are pervasive in the Monterey shale.

Figure 3c indicates the location of the formation, which straddles the San Andreas Fault. It has evolved in an active tectonic environment,[14] and evidence of its extensive tectonic displacements can be seen in figure 4. The deposition of the black shale occurred in several sedimentary basins, including Los Angeles, Ventura, and Santa Maria.

Those basins have yielded large quantities of oil for more than 100 years. Per acre, the Los Angeles basin, which includes the Long Beach, Huntington Beach, and Wilmington oil fields, has been among the world's most productive oil regions. The total oil extracted from California basins has been some 29 Bbbl. Annual production peaked at 394 Mbbl in 1984 and has decreased steadily to 196 Mbbl in 2012. The Monterey shale is the source of that oil, although much of the oil has been produced from younger strata into which the fuel migrated.

According to DOE estimates from 2011, the total recoverable oil in the 48 contiguous states is 24 Bbbl.[13] They attribute 15.4 Bbbl to the Monterey shale and 3.6 Bbbl to the Bakken shale, so the Monterey has great potential for future petroleum production. However, attempts to use super fracking to extract oil there have not been successful. In our view, the culprit is the extensive fracture permeability in the Monterey shale that has arisen from both natural fracking and tectonic deformation. The well-developed fracture networks in the shale have allowed some oil to migrate and be recovered, but they also prevent the buildup of the high fluid pressure required for super fracking to produce distributed fracture permeability.

Questions remain

In addition to the environmental issues spelled out in the box on page 36, several technical concerns will affect the long-term viability of high-volume fracking. One is the efficiency of extraction: What percent of the oil and gas in the tight shale reservoir is recovered and at what rate? Traditional oil and gas extraction consists of three stages. The primary stage extracts the oil and gas that flow to the vertical wells from the reservoir in which they are trapped. Typically, it manages to recover 20–30% of the oil and gas in the formation. The secondary stage usually

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Figure 4. The highly fractured Monterey shale, exposed near the Hayward fault in Berkeley, California. Dark bands are black shale. Tectonic movements have brought this sedimentary rock to the surface and rotated the beds from horizontal to vertical. (Photograph by Eldridge Moores.)

involves flooding the target reservoir with water, carbon dioxide, or nitrogen. Those fluids, introduced at injection wells, drive the oil and gas to production wells. Usually 40–50% of the oil and gas is recovered in stages one and two. The tertiary phase can involve steam injection to soften viscous oil, acid leaching to dissolve rock in the formation, or low-volume fracking. All told, the three stages typically collect 60–65% of the available oil and gas.

High-volume fracking of tight shale reestablishes the natural fracture permeability and also produces new fractures. But the process depends on the pressure naturally generated by the weight of the overlying rock to drive the fluid to the production well. In its reliance on natural fractures and pressure, high-volume fracking is similar to the primary stage of traditional extraction.

Energy consultant George King has estimated that prior to 2006, less than 10% of trapped gas was recovered from tight shale formations[1] but that subsequent technological advances have increased the fraction to as much as 45%. Unfortunately, the production rate declines with time. Typically, 65% of the total production from a super-fracking well is generated in the first year and 80% in the first two years.[1] That decline in production is considerably greater than in traditional oil and gas wells and requires that many high-volume fracking wells be drilled to maintain production.

Another important question is whether super fracking can be modified so that it is effective in extracting oil and gas from black shale reservoirs, such as the Monterey shale, that have open natural fractures. Would it be technically feasible, for example, to inject cement to seal the natural fractures before carrying out high-volume fracking? And can it be done in an environmentally responsible manner?

The use of high-volume fracking to extract large quantities of fossil fuels is a relatively recent development. As a result, energy producers lack scientific studies on which to base technological developments and assess environmental implications. The physical processes associated with high-volume fluid injection are poorly understood. Among the issues that will require detailed study are contamination, fluid leakage, and induced seismicity. We, along with our colleague J. Quinn Norris, are among the few who have attempted to model super fracking; our study is based on a type of graph-theory analysis called invasion percolation from a point source.[15]

High-volume fracking is such a successful tool for economically extracting oil and gas that its use will probably continue to expand for a long while. We emphasize, however, that tight shale oil and gas are nonrenewable sources of energy. Getting the most out of the shales that confine fossil fuels will buy some time for humankind to further develop renewable sources such as wind and solar, but it will not erase the need to ultimately transition to them.

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