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**Shale gas**

*Since 1990,  
Schlumberger has  
invested heavily in  
shale gas research  
and today leads the  
industry in key areas  
of the technology.*

**Executive summary**

Organically rich gas shale reservoirs, once ignored by drillers seeking easier plays and faster returns on their investments, are now boosting the fortunes of mid-sized producers across the United States. The prize is an estimated 500  $\times 10^{12}$  ft<sup>3</sup> (500 tcf) to 780 tcf of natural gas in place. The challenge is to release it from rock as impermeable as concrete. The prolific Barnett Shale in the Fort Worth basin covers much of North Central Texas, but organically rich shales are also present in the mature Illinois, Michigan, and Appalachian basins. Recent advances in drilling and completions (coiled tubing, perforating, and hydraulic fracturing), along with higher gas prices, are making shale gas production economical.

Since 1990, Schlumberger has invested heavily in shale gas research and today leads the industry in key areas of the technology.

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# Shale Gas

## The nature of gas shale reservoirs

Shale, which consists mainly of consolidated clay-sized particles, is the Earth's most common sedimentary rock. Shale looks like the slate of a chalkboard and generally has ultralow permeability. In many oil fields, shale forms the geologic seal that retains the oil and gas within producing reservoirs, preventing hydrocarbons from escaping to the surface. In a handful of basins, however, layers of shale—sometimes hundreds of feet thick and covering millions of acres—are both the source *and* reservoir for natural gas. These shales have one thing in common: They are rich in organic carbon.

Typically, the methane in organic shales was created in the rock itself over millions of years. Thermogenic gas forms when organic matter left in the rock breaks down under rising temperature. The gas that is generated is then adsorbed onto the organic material, expelled through leaks in the shale, or captured within pores of the shale. In some cases, however, an influx of water and the presence of bacteria will support the generation of biogenic gas.

Although it is difficult to extract, most shale gas is fairly clean and dry. That's because over time, there has been enough heat in the reservoir rock to break down any liquid hydrocarbons. The relative amounts of oil and gas contained in shale are one indication of how much heat has been in the reservoir, and for how long. Thermally mature shales have had enough heat and pressure to produce hydrocarbons. The most thermally mature shales will contain only dry gas. Less mature shales will have wetter gas, and the least thermally mature shales may contain only oil.

In rare cases, the produced methane may have small percentages of carbon dioxide, nitrogen, ethane, and even propane. Carbon dioxide is more commonly found in biogenic gas shales.

Gas shale reservoirs in the United States tend to be found within three depth ranges between 250 and 8,000 ft. The New Albany and Antrim shales, for example, have some 9,000 wells in the range of 250 to 2,000 ft. In the Appalachian basin shales and the Devonian and Lewis shales, there are about 20,000 wells from 3,000 to 5,000 ft. Although the Barnett and Woodford shales are much deeper, the Caney and Fayetteville shales are from 2,000 ft

to 6,000 ft, with most of the reservoirs between 2,500 and 4,500 ft. A good shale gas prospect has a shale thickness between 300 and 600 ft.

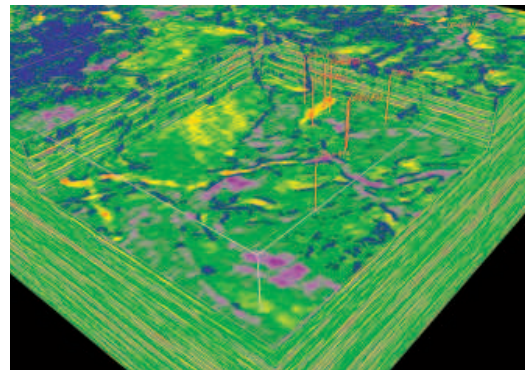
Shale has such low permeability that it releases gas very slowly, which is why shale is the last major source of natural gas to be developed. The good news is that shale can hold an enormous amount of natural gas. The most prolific shales are relatively flat, thick, and predictable, and the formations are so large that their wells will continue producing gas at a steady rate for decades.

## Currently producing shale reservoirs

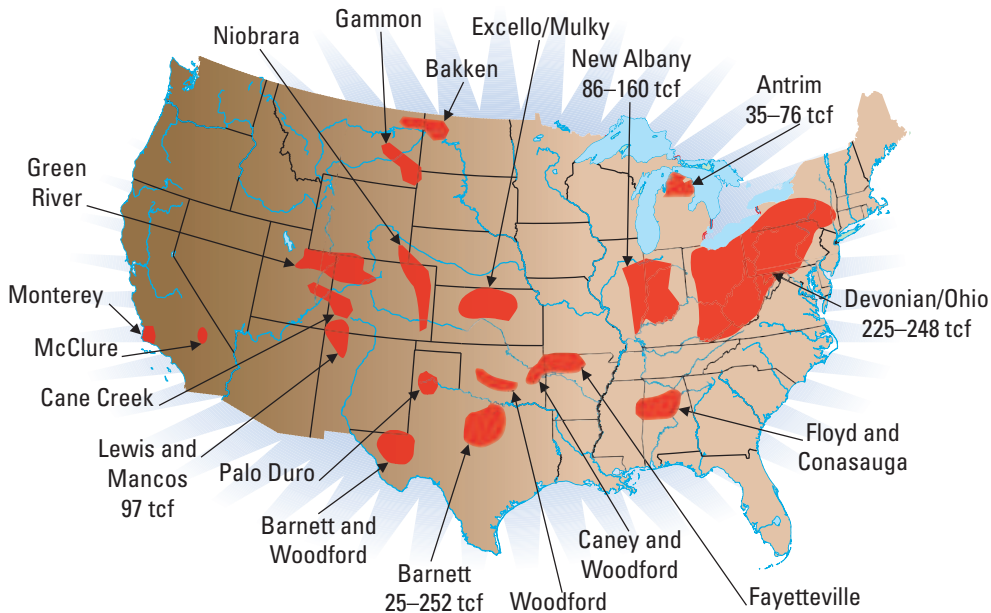
The Barnett Shale in the Fort Worth basin of North Central Texas is by far the most active shale gas play in the United States. The reservoir ranges from 100 ft to more than 1,000 ft in gross thickness and holds from  $50 \times 10^9 \text{ ft}^3$  (50 bcf) to 200 bcf of gas per square mile. The Gas Technology Institute estimates that organic shale reservoirs in the United States contain up to 780 *trillion* ( $780 \times 10^{12}$ )  $\text{ft}^3$  of gas. Equally gas-rich organic shales almost certainly exist elsewhere around the world, but so far the United States is the only country with a large shale gas industry.

## Why now?

Thomas Jefferson was still alive when the first commercial shale gas well was drilled in 1821. True, it was only 27 ft deep into the Devonian Dunkirk shale, but residents of the nearby village of Fredonia, New York, were happy to use the gas to illuminate their homes. Until recently, however, shale has been seen as only a source rock or seal for oil and gas. Gas shale reservoirs were not con-



*Three-dimensional seismic image of gas shale reservoir.*



Major shale gas basins in the United States with total resource potential of 500 to 1,000 tcf.

sidered significant or producible.

Supply and demand has always driven the oil and gas business, so natural gas did not become an important commodity until after World War II. To keep up with a growing market and depleting reservoirs, producers in the 1980s began looking beyond traditional sources of natural gas into the more difficult tight gas sands. By the early 1990s, they were also looking at coalbed methane. Today the industry is moving into shale. In 2000, there were 28,000 shale gas wells in the United States, with a combined production of more than 700 bcf per year.

Shale gas has now become an important part of the energy mix. The United States consumes about 23 tcf per year of natural gas, yet it produces only 19 tcf/year. Canada has been supplying the shortfall, but potential shortages loom as that nation's gas fields deplete and its internal demand increases. Meanwhile, the consumption rate in the United States continues to grow. With gas prices expected to stay near record highs, gas producers are increasingly willing to pursue shale gas ventures.

It would seem that with the long history of petroleum production in the United States, all prospective basins have been explored, but that's

not the case with shale. Except for the earliest wells, operators have historically ignored shale. What's more, shale gas can occur where there is no traditional oil and gas production, so many prospects remain unexplored. There's a fair amount of excitement that reminds some observers of the early days of the oil industry. Suddenly, many new areas are attractive. Shale gas operators across the Mid-Continent and Western United States are leasing hundreds of thousands of acres, all looking for the next big play.

### The technology behind it

Effective, economic hydraulic fracturing and horizontal drilling are the primary enabling technologies behind the recent surge in shale gas production. Long a dream of the petroleum industry, horizontal drilling came into widespread use in the mid-1990s. Horizontal drilling has been an efficient way of removing gas from conventional reservoirs, coal seams, and even from tight gas reservoirs. Now drillers are using it to enhance recovery rates in the ultralow permeabilities they encounter in shale.

Studies published by Schlumberger engineers 15 years ago demonstrated the potential for horizontal wells in shale formations. That helped

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# Shale Gas

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jump-start producers' interest. In 1999 there were only four horizontal wells in the Barnett Shale, but by the end of 2004, there were 744. In general, horizontal wells in the Barnett cost twice as much as vertical wells, but their initial production rates and estimated ultimate recoveries are three times greater.

Early low-permeability horizontal wells were considered failures because they did not naturally produce at commercial rates. The explosive growth of horizontal wells in shales is due to improvements in completion technologies. Multistage stimulation treatments are now performed on these wells to place hydraulic fractures around the borehole. The ability to economically perforate, stimulate, and isolate multiple points along the lateral has made these wells commercial successes.

The pore spaces in organic shale are not large enough for even tiny methane molecules to flow through easily. The rock may, however, contain natural fractures caused by pressure from the overlying rock and the natural movements of the earth's crust. Stress loads in the reservoir determine the geometry of the fractures, which are often concentrated in fracture swarms.

Shale gas wells are not hard to drill, but they are difficult to complete. In almost every case, the rock around the wellbore must be hydraulically fractured before the well can produce significant amounts of gas. Fracturing involves isolating sections of the well in the producing zone, then pumping fluids and *proppant* (grains of sand or other material used to hold the cracks open) down the wellbore through perforations in the casing and out into the shale. The pumped fluid, under pressures up to 8,000 psi, is enough to crack shale as much as 3,000 ft in each direction from the wellbore. In the deeper high-pressure shales, operators pump *slickwater* (a low-viscosity water-based fluid) and proppant. Nitrogen-foamed fracturing fluids are commonly pumped on shallower shales and shales with low reservoir pressures.

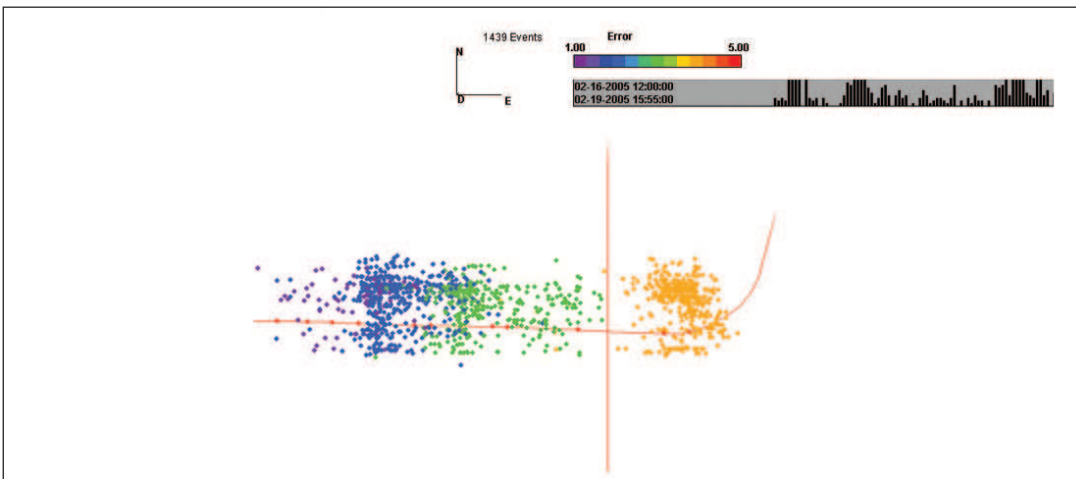
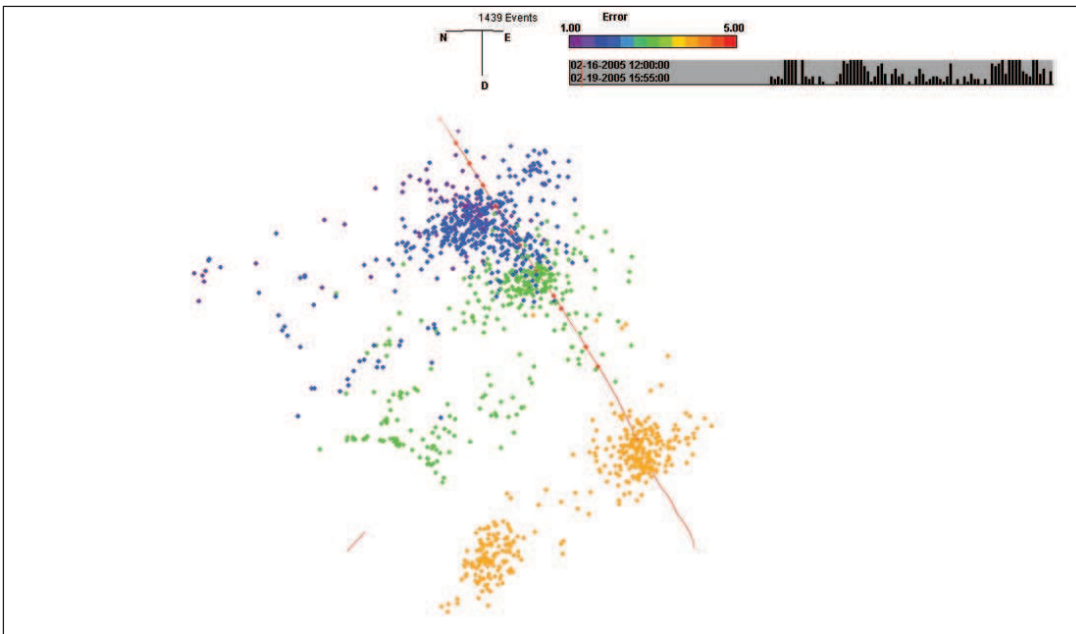
## The art of hydraulic fracturing

Hydraulic pressure created by pumping fluid into the well opens cracks in the shale, but keeping them open after the pressure is released while the well is producing is a tricky process. Under pressure, fractures nearest the wellbore may be as large as one-eighth to one-quarter inch wide. To keep them open, solid propping materials (proppants) are added to the pumped fluid.

A simple fracturing job may pump a mixture of water and sand into the well. The water creates the pressure to initiate the fractures, then carries the sand into the cracks as they grow. When the fluid pressure is released, the grains of sand hold the cracks open. Even without proppant, the cracks may stay open for a while, but they will eventually heal and the gas production will decline accordingly. Refracturing can restore production in existing wells and economically increase the amount of gas recovered.

The technology, of course, is much more complicated than that. Although water and sand are the cheapest fluid and proppant, they are not always the best. High-tech fracturing fluids are more viscous and better able to maintain the proppant in suspension, allowing it to travel deeper into the fractures and reduce the amount of settling that occurs before the fractures close. Advanced designs for artificial proppants, used in addition to sand, also do a better job of holding open the cracks without restricting the flow of gas. The use of these high-tech fluids and proppants may eliminate the need for additional refracture stimulation treatments later on.

Fractures are the key to good production. The more fractures in the shale around the wellbore, the faster the gas will be produced. Because of shale's extremely low permeability, the best fracture treatments are those that expose as much of the shale as possible to the pressure drop that allows the gas to flow. The natural formation pressure of a large gas shale reservoir will decline only slightly over decades of production. Any pressure drop on individual wells is likely the result of fractures closing up, rather than depletion of the reservoir. The key to good shale gas production over time is having the proper distribution and placement of proppant to keep the fractures open.



Plan view and side view of microseismic events recorded during a four-stage stimulation completion on a Barnett Shale horizontal well. The events are color-coded by stage.

## Economics of shale gas

There are fundamental differences in the production of gas from shale and gas produced from other unconventional sources. Many tight gas sands, for example, yield a tremendous amount of gas for the first few months, but then production declines significantly and often becomes uneconomical after a relatively short time.

Shale gas is completely different. Shale gas wells don't come on as strong as tight gas, but once the production stabilizes, they will produce consistently for 30 years or more. Suppose that new horizontal wells in a typical shale gas play produce 1 million ft<sup>3</sup> per day (1 MMcf/d). If the operator puts 10 such wells on 1 square mile, that section will produce 10 MMcf/d. With an estimated 120 bcf of gas per square mile in the ground, these gas shale reservoirs will be producing gas for a very long time. That realization,

plus increasingly effective horizontal drilling tools, 3D seismic imaging, and advanced reservoir modeling software, has many people looking at shale gas as an important new resource.

The price of gas is linked to oil and based on each fuel's heating value. The ratio is about 6 to 1. In other words, 1 bbl of oil contains about 6 times more heat energy than 1,000 ft<sup>3</sup> of gas. If a barrel of oil sells for USD 50.00, then 1,000 ft<sup>3</sup> of gas is worth about USD 8.00. As long as oil prices remain high, there is no reason for natural gas prices to go down. Although gas is abundant in much of the world, it is expensive and potentially dangerous to transport internationally.

Medium and large independent oil and gas companies are showing the most interest in shale gas. Very small producers with only a handful of wells may have a difficult time acquiring enough acreage to be profitable in shale.

### Technology gains and trends

Much of the research for the recovery of shale gas is focused on more efficient ways to fracture the shale. Fracturing is the key to a successful shale gas well. Many of the new deeper shale gas wells are horizontal, and the cost of fracturing them can be as much as 25 % of the total cost of the well. Operators must determine the payoff for spending the money to fracture more of the reservoir.

Fracture jobs are commonly performed in stages. In each stage, operators pump fluid and proppant through the perforation clusters into a portion of the formation. They then set a plug, move up the wellbore, perforate, and repeat the process. Each move is one stage. Ideally, the well should be fractured in as many stages as possible, but the cost would be prohibitive.

Operators typically pump a stage, using from 2 to 4 perforation clusters for every 500 ft of lateral section. The problem is, with a 2,000-ft lateral and only 4 stages, there are just 8 to 16 zones of entry. That leaves almost 90 % of the rock untouched. One hot area of shale gas research is seeking ways to complete the greatest number of stages as cheaply as possible in a horizontal well. Ideally, the best scenario would be to pump 40 or 50 smaller stages, putting the fractures as close together as possible, but that is not practical and far too expensive with current technology.

One approach that Schlumberger is examining is to reconsider the directions of the fractures themselves. Because of natural stresses on the rock, we know that adding pressure during a fracturing job will cause cracks to grow in certain directions. Current thinking is that the fractures should grow out at right angles, away from the wellbore. Most shale gas wells are designed that way. But would planning the well so that the fractures run parallel to the wellbore be more efficient? It's possible that one large longitudinal fracture may be just as good—and more cost-effective—than multiple transverse fractures.

The proppant and pumping fluid are two other areas of continuing research. Water and sand are the two most common materials used in fracture jobs in the Barnett Shale, but in other shales, operators are having trouble getting enough proppant into the cracks. In these slickwater fracturing jobs, water is pumped along with a small amount of polymer to reduce the pipe friction pressure. Often, however, slickwater jobs do not create fractures wide enough for the proppant (usually sand) to be pumped through them. In addition, the sand that does make it into the fractures can quickly settle out of the water. The result is cracks that are less permeable than they should be.

To overcome the problem, Schlumberger has developed pumping fluids that suspend the proppant for very long times. That keeps the proppant in the right place as the fractures slowly close down. Two such technologies are ClearFRAC\* and FiberFRAC\* fracturing systems. ClearFRAC fluid is solids-free and has excellent capacity to transport solids. It is very effective at carrying sand far into the fracture and keeping it suspended so that the fracture will remain open once the well is placed on production. The fact that ClearFRAC fluid is itself free of solids is helpful, because any solids mixed in with the sand pack will reduce the permeability and corresponding gas production rate.

FiberFRAC fracturing fluid technology also provides excellent solids transport and suspension capability. Like ClearFRAC fluid, it leaves the sand free of any solids that could reduce the permeability of the fractures. When it is being pumped, FiberFRAC fluid contains a network of solids that suspends the sand and helps it work its way deep into the cracks. FiberFRAC fluid keeps the sand suspended until the crack closes on the sand during production. The fibers dissolve over time, leaving the permeability of the sand very high. FiberFRAC fluid couples excellent sand transport and suspension properties, producing the highest possible permeability within the fractures.

## How much gas is there?

To find out the potential of a reservoir, you must know the percentage of total organic carbon (TOC) within the rock. Without that information, you cannot accurately determine the matrix porosity and water saturation of the reservoir.

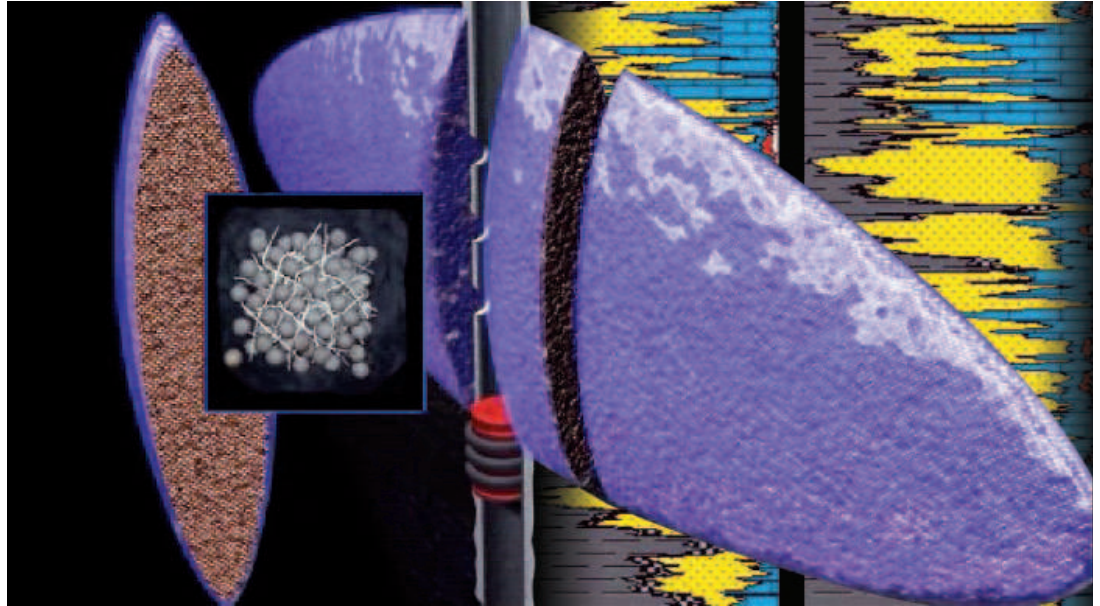
One of Schlumberger's main advantages is its proprietary wireline logging technology. With it, we can quantify the amount of gas within the shale, including free gas within the pores and gas adsorbed onto organic matter. Porosity is a key parameter for both quantifying the amount of free gas and estimating the permeability of the shale. To determine porosity, you first need an accurate matrix density. Schlumberger uses geochemical



*Solids-free ClearFRAC technology provides excellent proppant transport and fracture permeability.*



# Shale Gas



*Fiber-based mechanical support for proppant pack. The FiberFRAC treatment creates a fiber-based network within the fracturing fluid, providing a mechanical means to transport, suspend, and place the proppant.*

logs to quantify the complex mineralogy of shales, including the amount of carbonates, pyrites, clay, quartz, and TOC.

Remember that the organic matter within these shales is not only the source for the gas, it is also a molecular sponge that gas can adsorb onto. Using a combination of conventional triple-combo and geochemical logs, we can determine the organic carbon content of the shale and calculate for adsorbed gas. We also use data from the geochemical logs to differentiate between types of clays, knowledge that is important for determining which fluid to use for hydraulic fracturing.

Schlumberger's electrical imaging and sonic services are used to identify natural and drilling-induced fractures to find regions within the shale that will have the greatest permeability. Placing perforation clusters in those zones will produce gas at the highest rates. Sonic and density data are also used to design hydraulic fractures and estimate the containment of vertical fractures.

Formation pressure is a key component in most shale gas calculations, and Schlumberger has the industry's only wireline system and analysis methodology, the PressureXpress\* service, that can measure the formation pressure of a potential gas shale reservoir.

Conventional horizontal directional drilling technologies have been used to drill shale gas wells, including a wide variety of bits and downhole motors. Measurement while drilling (MWD) is also used, along with basic gamma ray logging techniques. The limiting factors of conventional drilling techniques are the torque and drag generated by the traditional slide-and-rotate sequence used to build inclination and azimuth in the well. In longer horizontal wells, the cumulative torque and drag can limit total depth and make it difficult to log the well.

Rotary steerable systems have been used in some wells to produce straighter, less tortuous wellbores that can vary by less than 0.5° in inclination from heel to toe. The geoVISION 675\* laterolog resistivity tool has been used in a number of wells, in a recorded drilling mode, to produce resistivity images and wellbore formation dip analysis of the wellbore while drilling. The images, viewed with the aid of high-resolution processing, provide an accurate and cost-effective way to interpret the wellbore. Using these images, for example, we can compare natural formation fractures to drilling-induced fractures and determine the best targets for perforating and stimulating the well.

### **The future of shale gas**

Until recently, there was very little specialized oilfield technology to help produce gas shale reservoirs. Schlumberger is a pioneer in this field. With the growing demand for natural gas in the United States, and the fact that many US gas fields are in decline, Schlumberger believes that every new source of natural gas should be exploited. While no single source will completely fill the gap, we believe that shale gas is part of the solution, and Schlumberger is working hard to deliver answers to its many clients.

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## Contacts

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Microseismic: John Thompson, Kevin Tanner, and Joel Le Calvez

Well testing and production logs: Marc Percy

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