Producing Gas from Its Source

Shale, the most abundant of sedimentary rocks, is finally getting its due. Shale has long been regarded as a sealing rock that drillers passed through on their way to striking pay in sandstone or carbonate formations. However, thanks to the right combination of geology, economics and technology, organic-rich shales are prompting US operators to lease drilling rights to thousands of acres in a drive to discover the next shale-gas province.

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1. Other types of continuous gas resources listed by the USGS are basin-centered gas, tight gas and coalbed gas.
2. Schenk CJ: "Geologic Definition of Conventional and Continuous Accumulations in Select U.S. Basins—The 2001 Approach," Abstract for AAPG Hedberg Research Conference on Understanding, Exploring and Developing Tight Gas Sands, Vail, Colorado, USA, April 24–29, 2005.
3. Matrix permeability refers to the capability of fluids to flow through a rock, primarily by way of interstices between mineral grains that make up the rock, but does not include flow through fractures in the rock.

Millions of oil or gas wells drilled over the past 150 years have penetrated substantial intervals of shale before reaching their target depths. With so much shale exposure, is every dry hole actually a potential shale-gas producer? Certainly not. Shale gas is produced only under certain conditions.

Shale, an abundant sedimentary rock of extremely low permeability, is often considered a natural barrier to the migration of oil and gas. In gas shales, the gas is generated in place; the shale acts as both the source rock and the reservoir. This gas can be stored interstitially within the pore spaces between rock grains or fractures in the shale, or it can be adsorbed to the surface of organic components contained within the shale. Contrast this to conventional gas reservoirs, in which gas migrates from its source rock into a sandstone or carbonate formation where it accumulates in a structural or stratigraphic trap, often underlain by a gas/water contact. It should come as no surprise, therefore, that gas shales are considered unconventional reservoirs.

Shale gas is produced from continuous gas accumulations, according to the US Geological Survey (USGS).[1] The USGS lists 16 traits, any or all of which may be present in continuous gas accumulations.[2] Those traits that are particularly characteristic of gas shale include regional extent, lack of an obvious seal and trap, absence of a well-defined gas/water contact, natural fracturing, estimated ultimate recovery (EUR) that is generally lower than that of a conventional accumulation and very low matrix permeability.[3] Furthermore, economic production depends heavily on completion technology.

Despite their apparent shortcomings, in the USA, certain shales are being targeted for production—those with the right combination of shale type, organic content, maturity, permeability, porosity, gas saturation and formation fracturing. When these formation conditions are triggered by favorable economic conditions, an unconventional gas play becomes a boom.

Today's shale-gas plays are taking off, thanks largely to a growing demand for gas, and equally important, to a growing range of advanced oilfield technologies. This trend is expanding in the United States, where rising gas prices and consumption of nearly 23 Tcf [651,820 million m³] of gas per year are fueling an increase in onshore drilling. E&P companies are leasing drilling rights to hundreds of thousands of acres, while advanced drilling and completion technologies are helping to extend the boundaries of known shale-gas basins. These plays are also pushing the boundaries of science, prompting a closer look at this common detrital rock, and spurring development of new instruments and techniques to evaluate shale resources.

In this article, we discuss the conditions required for shale to generate hydrocarbons, the conditions required to create shale-gas reservoirs, and the technology required to exploit and produce those reservoirs. We will also review some of the practices used in the Barnett Shale of north-central Texas.
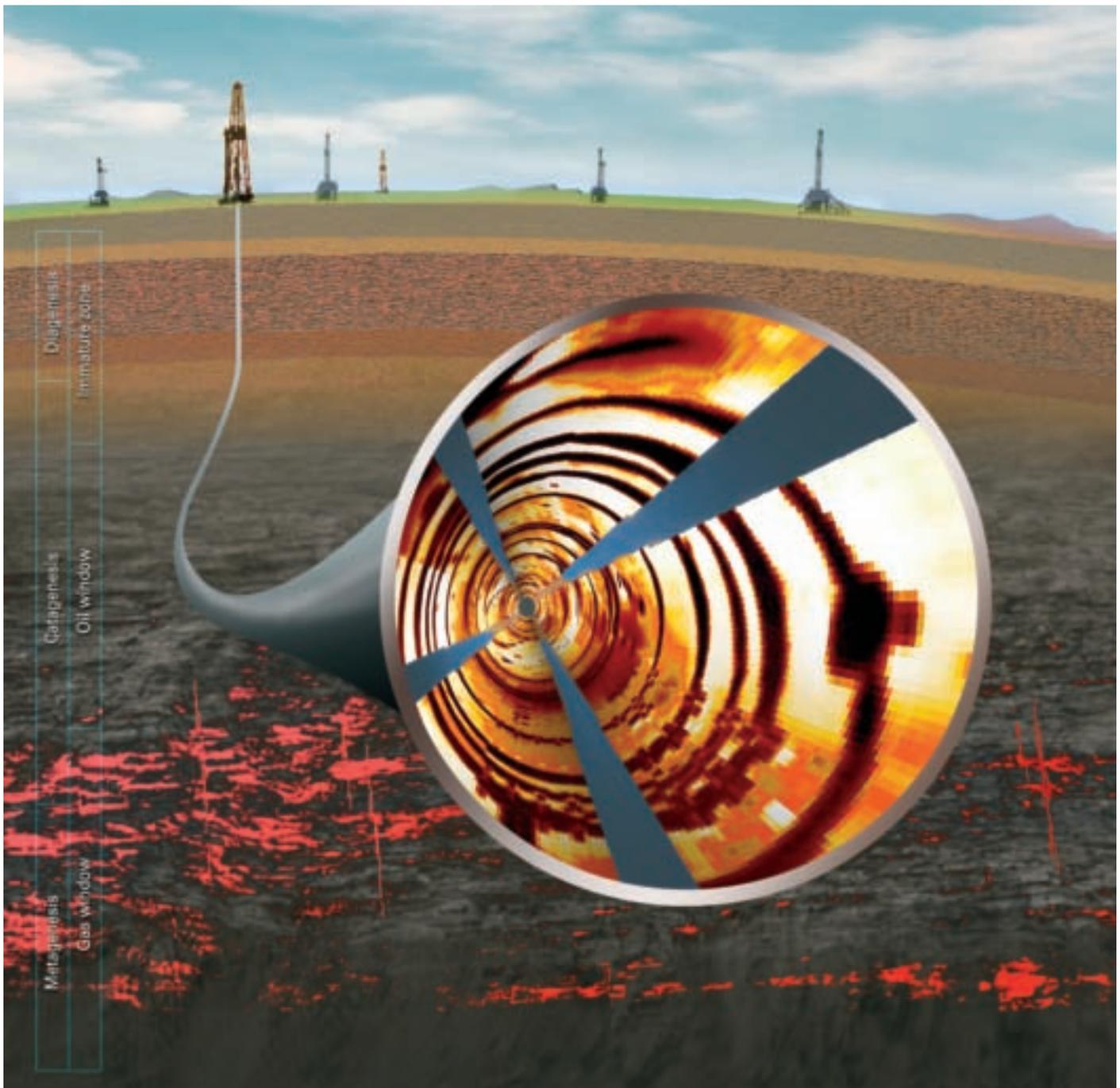
The Hydrocarbon Source

Shale comprises clay- and silt-sized particles that have been consolidated into rock layers of ultralow permeability. Clearly, this description offers little to commend shale as a target for exploration and development. However, some shales are known to contain enough organic matter—and it doesn't take much—to generate hydrocarbons. Whether these shales are actually capable of generating hydrocarbons, and whether they generate oil or gas, depends largely on the amount and type of organic material they contain; the presence of trace elements that might enhance chemogenesis; and the magnitude and duration of heating to which they have been subjected.

Organic matter, the remains of animals or plants, can be thermally altered to produce oil or gas. Before this transformation can take place, however, those remains must first be preserved to some degree. The degree of preservation will have an effect on the type of hydrocarbons the organic matter will eventually produce.

Most animal or plant material is consumed by other animals, bacteria or decay, so preservation usually requires quick burial in an anoxic environment that will inhibit most biological or chemical scavengers. This requirement is met in lake or ocean settings that have restricted water circulation, where biological demand for oxygen exceeds supply, which occurs in waters containing
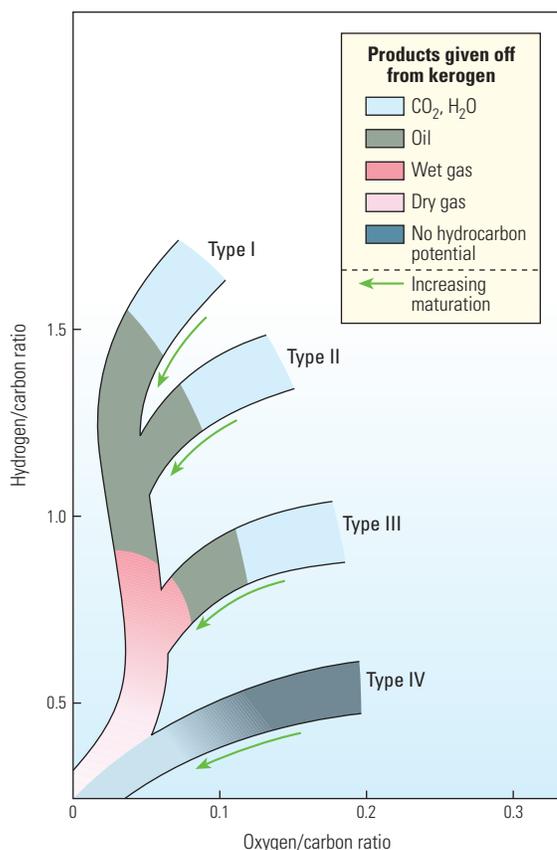
^ Evolution of kerogen. A modified Van Krevelen diagram shows changes to kerogen brought on by increased heat during burial. The general trend in the thermal transformation of kerogen to hydrocarbon is characterized by generation of nonhydrocarbon gases, and then progresses to oil, wet gas and dry gas. During this progression, the kerogen loses oxygen primarily as it gives off CO_2 and H_2O; later, it begins to lose more hydrogen as it evolves hydrocarbons.

less than 0.5 milliliters of oxygen per liter of water.[4] Even in these settings, however, anaerobic microorganisms can feed off the buried organic matter, producing biogenic methane in the process.

Further sedimentation increases the depth of burial over time. The organic matter slowly cooks as pressure and temperature increase in concert with greater burial depths. With such heating, the organic matter—primarily lipids from animal tissue and plant matter, or lignin from plant cells—is transformed into kerogen.[5] Depending on the type of kerogen produced, further increases in temperature, pressure and time may yield oil, wet gas or dry gas (left).

Kerogen, an insoluble material formed by degradation of organic matter, is the primary ingredient in the generation of hydrocarbons. Kerogen has been classified into four broad groups, each of which has a distinct bearing on what type of hydrocarbons, if any, will be produced.[6]

• Type I kerogen: generated predominantly from lacustrine environments and, in some cases, marine environments. It is derived from algal, planktonic or other matter that has been strongly reworked by bacteria and microorganisms living in the sediment. Rich in hydrogen and low in oxygen, it is prone to oil production, but can also produce gas, depending on its stage of thermal evolution. Type I kerogens are not found widely, and are responsible for only 2.7% of the world's oil and gas reserves.[7]

• Type II kerogen: typically generated in reducing environments found in moderately deep marine settings. This type is derived primarily from the remains of plankton that have been reworked by bacteria. It is rich in hydrogen and low in carbon. It can generate oil or gas with progressive heating and maturation. Sulfur is associated with this type of kerogen, either as pyrite and free sulfur, or in organic structures of kerogen.[8]

• Type III kerogen: derived primarily from terrestrial plant debris that has been deposited in shallow to deep marine or nonmarine environments. Type III kerogen has lower hydrogen and higher oxygen content than Types I or II, and consequently generates mostly dry gas.

• Type IV kerogen: typically derived from older sediments redeposited after erosion. Prior to deposition, it may have been altered by subaerial weathering, combustion or biological oxidation in swamps or soils. This type of kerogen consists of residual organic matter with high carbon content and no hydrogen. It is considered a form of "dead carbon," with no potential for generating hydrocarbons.[9]

4. Demaison GJ and Moore GT: "Anoxic Environments and Oil Source Bed Genesis," *AAPG Bulletin* 64, no. 8 (August 1980): 1179–1209.

5. Kerogen, which literally means "producer of wax," was originally used to denote the insoluble organic material found in oil shales of Scotland. The term has been loosely used since its inception, and its meaning has devolved to encompass insoluble organic matter in sedimentary rock that is the source of most petroleum. For more on kerogen definitions: Hutton A, Bharati S and Robl T: "Chemical and Petrographic Classifications of Kerogen/Macerals," *Energy & Fuels* 8, no. 6 (November 1994): 1478–1488.

6. Tissot BP: "Recent Advances in Petroleum Geochemistry Applied to Hydrocarbon Exploration," *AAPG Bulletin* 68, no. 5 (May 1984): 545–563.

   Bordenave M-L: *Applied Petroleum Geochemistry.* Paris: Editions Technip, 1993.

   Demaison and Moore, reference 4.

7. Klemme HD and Ulmishek GF: "Effective Petroleum Source Rocks of the World: Stratigraphic Distribution and Controlling Depositional Factors," *AAPG Bulletin* 75, no. 12 (December 1991): 1809–1851.

8. Vandenbroucke M: "Kerogen: From Types to Models of Chemical Structure," *Oil & Gas Science and Technology—Revue de l'Institut Français du Pétrole* 58, no. 2 (2003): 243–269.

9. Tissot, reference 6.

10. Baskin DK: "Atomic H/C Ratio of Kerogen as an Estimate of Thermal Maturity and Organic Matter Conversion," *AAPG Bulletin* 81, no. 9 (September 1997): 1437–1450.

11. Bitumen, organic matter that is soluble in organic solvents, is a thermally degraded derivative of kerogen. The exact relationship between kerogen, bitumen and the hydrocarbons that evolve during heating of organic matter is still being investigated.

12. Peters KE, Walters CC and Moldowan JM: *The Biomarker Guide: Biomarkers and Isotopes in the Environment and Human History, 2nd Edition.* Cambridge, England: Cambridge University Press, 2004.

13. Aizenshtat Z, Stoler A, Cohen Y and Nielsen H: "The Geochemical Sulphur Enrichment of Recent Organic Matter by Polysulfides in the Solar-Lake," in Bjorøy M et al (eds): *Advances in Organic Geochemistry.* Chichester, England: Wiley (1981): 279–288.

14. Peters et al, reference 12.

15. Cracking is a process in which high temperature and pressure act upon large, heavy hydrocarbon molecules, causing them to split into smaller, lighter components. Under such conditions, oil can be transformed into a gas.

16. Peters et al, reference 12.

17. Hood A, Gutjahr CCM and Heacock RL: "Organic Metamorphism and the Generation of Petroleum," *AAPG Bulletin* 59, no. 6 (June 1975): 986–996.

18. Fresh cores are most preferred, while outcrop samples are less desirable, simply because outcrop samples tend to be degraded through weathering.

From this discussion, we can generalize that marine or lacustrine kerogens (Types I and II) tend to produce oils, while kerogens of terrestrial origin (Type III) produce gas. Intermediate blends of kerogens, especially Types II and III, are most common to marine shale facies.

A theme prevailing within this kerogen classification pertains to hydrogen content. Hydrogen-rich kerogens play a greater role in generating oil. Conversely, kerogen with lower amounts of hydrogen will generate gas. After hydrogen is depleted from the kerogen, generation of hydrocarbons will cease naturally, regardless of the amount of available carbon.[10]

Kerogen Maturity

Geological processes for converting organic material to hydrocarbons require heat and time. Heat gradually increases over time as the organic matter continues to be buried deeper under increasing sediment load; time is measured over millions of years. Through increasing temperature and pressure during burial, and possibly accelerated by the presence of catalyzing minerals, organic materials give off oil and gas. This process is complicated and not fully understood; however, the conceptual model is fairly straightforward. Microbial activity converts some of the organic material into biogenic methane gas. With burial and heating, the remaining organic materials are transformed into kerogen. Further burial and heat transform the kerogen to yield bitumen, then liquid hydrocarbons, and finally thermogenic gas—starting with wet gas and ending at dry gas.[11]

The process of burial, conversion of organic matter and generation of hydrocarbons can generally be summed up in three broad steps (above right).

Diagenesis begins the process. It is often characterized by low-temperature alteration of organic matter, typically at temperatures below about 50°C [122°F].[12] During this stage, oxidation and other chemical processes begin to break down the material. Biological processes will also alter the amount and composition of organic material before it is preserved. At this point, bacterial decay may produce biogenic methane. With increasing temperatures and changes in pH, the organic matter is gradually converted to kerogen and lesser amounts of bitumen.

During the early phases of diagenesis, sulfur may be incorporated into the organic matter. Sulfates in seawater provide the oxidant source for biodegradation of organic matter by sulfate-reducing bacterial colonies. These bacteria release polysulfides, hydrogen sulfide [H_2S] and native sulfur, which can later recombine with iron in clays to form pyrite [FeS_2], or combine with the organic matter to form other organosulfur compounds.[13]

Catagenesis generally occurs as further burial causes more pressure, thereby increasing heat in the range of approximately 50° to 150°C [122° to 302°F], causing chemical bonds to break down within the shale and the kerogen.[14] Hydrocarbons are generated during this process, with oil produced by Type I kerogens, waxy oil produced by Type II kerogens, and gas produced by Type III kerogens. Further increases in temperature and pressure cause secondary cracking of the oil molecules, resulting in production of additional gas molecules.[15]

Metagenesis is the last stage, in which additional heat and chemical changes result in almost total transformation of kerogen into carbon. During this stage, late methane, or dry gas is evolved, along with nonhydrocarbon gases such as CO_2, N_2 and H_2S. In basins where these changes take place, temperatures generally range from about 150° to 200°C [302° to 392°F].[16]

Overall, this process of kerogen alteration, commonly known as "maturation," produces a series of progressively smaller hydrocarbon molecules of increasing volatility and hydrogen content, eventually arriving at methane gas. And as the kerogen evolves through thermal maturity, its chemical composition progressively changes, transforming into a carbonaceous residue of decreasing hydrogen content, eventually ending as graphite.[17]

The preservation and maturation of organic matter are not unique to gas shales. The model for generating oil and gas is actually the same for conventional and unconventional resources. The difference, however, is location. In conventional reservoirs, oil and gas migrate from the source rock to the sandstone or carbonate trap. In unconventional shale-gas reservoirs, hydrocarbons must be produced straight from the source rock.

Evaluating Source-Rock Potential

Source-rock potential is primarily determined through geochemical analysis of shale samples, often in conjunction with detailed evaluation of logs from previously drilled wells. Geochemical testing is carried out on whole cores, sidewall cores, formation cuttings and outcrop samples.[18] The primary aim of testing is to determine whether the samples are organic-rich and whether they are capable of generating hydrocarbons. In general, the higher the concentration of organic matter in a rock, the
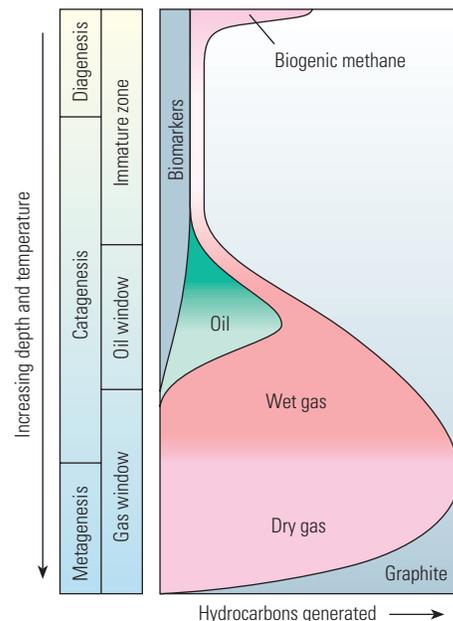
^ Thermal transformation of kerogen. Generation of hydrocarbons in source rocks is controlled primarily by temperature, as the kerogen content evolves from reactive carbon to dead carbon. Gas is given off during early diagenesis, primarily through biologic activity. Catagenesis takes place with further burial, during which oil and gas are given off. With increasing depth and temperature, any remaining oil is cracked, giving off gas.

Total Organic Content, Weight %	Kerogen Quality
< 0.5	Very poor
0.5 to 1	Poor
1 to 2	Fair
2 to 4	Good
4 to 12	Very good
> 12	Excellent

^ Organic content of source rock. The minimum cutoff for shales is usually considered to be 0.5% total organic content (TOC). At the other extreme, some geoscientists assert that it is possible to have too much organic matter. Excess kerogen can fill pore spaces that might otherwise be occupied by hydrocarbons.

better its source potential (above). A variety of sophisticated geochemical techniques have been developed to assess the total organic content (TOC) and maturity of samples.

TOC values can be obtained from 1-gram [0.0022-lbm] samples of pulverized rock that are treated to remove contaminants, then combusted at 1,200°C [2,192°F]. Carbon contained
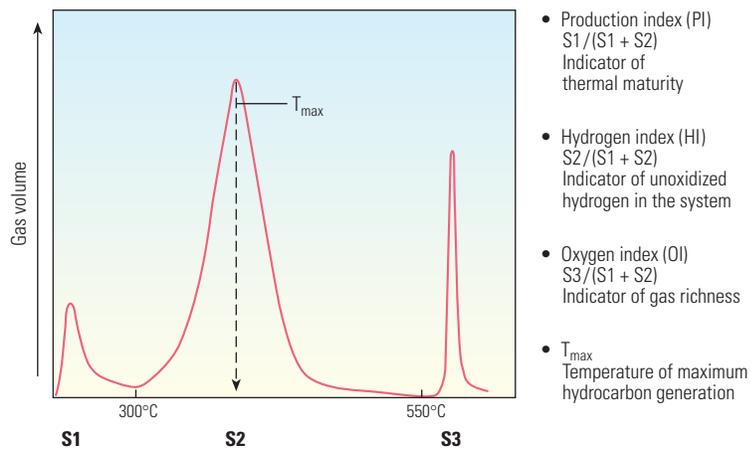
^ Gas peaks versus temperature. Rock samples are heated in two stages. The S1 peak represents milligrams of free hydrocarbons that can be thermally distilled from one gram of rock during the first stage of heating to about 300°C. The S2 peak records hydrocarbons generated by thermal cracking of kerogen during the second stage of heating up to about 550°C. This curve represents the residual petroleum potential of the rock, or the quantity of hydrocarbons that the rock could still produce if burial and maturation continue. The S3 peak charts milligrams of CO_2 produced by the kerogen as it is heated. T_{max} values give an approximate indication of source-rock maturity.

in the kerogen is converted to CO_2 or CO. The evolved carbon fractions are measured in an infrared cell, and converted to TOC, recorded as mass weight percent of rock. If this initial screening test detects samples of sufficient organic richness, they will be subjected to additional testing.

To further characterize organic richness, many geochemical laboratories use a programmed pyrolysis technique developed by the Institut Français du Pétrole.[19] This method, which has become an industry standard for geochemical testing of source rock, requires only 50 to 100 mg [0.00011 to 0.00022 lbm] of pulverized rock, and can be carried out in about 20 minutes. Each sample is heated in controlled stages through a pyrolysis test. During the first stage of heating to 300°C [572°F], free hydrocarbons in the rock are released from the matrix.[20] As heat increases during the second stage to 550°C [1,022°F], volatile hydrocarbons formed by thermal cracking are released. In addition to hydrocarbons, the kerogen gives off CO_2 as temperatures climb from 300°C to 390°C [572°F to 734°F].[21] Organic compounds released through heating are measured by a flame-ionization detector.

These measurements, along with temperature, are recorded on a chart and show three distinct peaks (above). These peaks give geochemists insight into the relative abundance of hydrogen, carbon and oxygen in the kerogen.[22] With this information, geochemists can determine kerogen type and potential for oil and gas generation.

The temperature at which the maximum release of hydrocarbons is detected corresponds to the tip of the S2 peak, and is called T_{max}. The thermal maturation of a sample can be tied to the value of T_{max}.

Vitrinite reflectance is another diagnostic tool for assessing maturation. A key component of kerogen, vitrinite is a shiny substance formed through thermal alteration of lignin and cellulose in plant cell walls. With increasing temperature, vitrinite undergoes complex, irreversible aromatization reactions, resulting in increased reflectance.[23] Vitrinite reflectance was first used to diagnose the rank, or thermal maturity, of coals. This technique was later carried over to evaluate thermal maturity of kerogens. Because reflectance increases with temperature, it can be correlated to temperature ranges for hydrocarbon generation. These ranges can be further divided into oil or gas windows.

Reflectivity (R) is measured through a microscope equipped with an oil-immersion objective lens and photometer.[24] Vitrinite-reflectance measurements are carefully calibrated against glass- or mineral-reflectance standards, and reflectance measurements represent the percentage of light reflected in oil (Ro). When a mean value of vitrinite reflectivity is determined from multiple samples, it is designated as Rm.

As an indicator of thermal maturity, Ro values vary from one organic type to another. This means that the onset of hydrocarbon generation in Type I organic matter may be different than in Type II organics. And because the temperature range of the gas window extends beyond that of oil, Ro values for gas will show a corresponding increase over those of oil. Thus, high maturation values ($Ro>1.5\%$) generally indicate the presence of predominantly dry gas; intermediate maturation values ($1.1\%<Ro<1.5\%$) indicate gas with an increasing tendency toward oil generation at the lower end of the range. Wet gas can be found still lower in the range ($0.8\%<Ro<1.1\%$). Lower values ($0.6\%<Ro<0.8\%$) indicate predominantly oil, while $Ro<0.6\%$ points to immature kerogen.

By themselves, Ro values can sometimes be misleading, and should be weighed along with other measurements. Other common indicators of maturity involve the thermal alteration index (TAI), based on microscopic examination of spore color; pyrolysis temperature evaluation; and, to a lesser extent, conodont alteration index (CAI), based on examination of tiny fossilized

19. Espitalie J, Madec M, Tissot B, Mennig JJ and Leplat P: "Source Rock Characterization Method for Petroleum Exploration," paper OTC 2935, presented at the 9th Annual Offshore Technology Conference, Houston, May 2–5, 1977.

20. Other variations on this method use slightly different temperature ranges.

21. Alixant J-L, Frewin N, Nederlof P and Al Ruwehy N: "Characterization of the Athel Silicilyte Source Rock/Reservoir: Petrophysics Meet Geochemistry," Transactions of the SPWLA 39th Annual Logging Symposium, Keystone, Colorado, May 26–29, 1998, paper LL.

22. Peters KE: "Guidelines for Evaluating Petroleum Source Rock Using Programmed Pyrolysis," AAPG Bulletin 70, no. 3 (March 1986): 318–329.

23. Peters KE and Cassa MR: "Applied Source Rock Geochemistry," in Magoon LB and Dow WG (eds): The Petroleum System—From Source to Trap: AAPG Memoir 60. Tulsa: AAPG (1994): 93–120.

24. The terms reflectance and reflectivity tend to be used interchangeably, with the former being more common.

However, reflectivity is a measure of reflectance. Reflectance is a ratio of the light reflected from a surface to the light directed onto that surface—the ratio of reflected radiation to incident radiation. This value can change, up to a point, depending on the thickness, and hence, opacity, of a surface. If that surface is thick enough to prevent light from being transmitted through the surface, then reflectance reaches a maximum. This is the reflectivity of a surface.

25. For well over a century, tiny, cone-shaped fossils known as conodonts were a mystery for paleontologists. Found in Late Cambrian and Triassic formations, conodonts were long suspected of being teeth. In the early 1990s, this supposition was verified through the aid of electron microscopy. For more on conodont research: Zimmer C: "In the Beginning Was the Tooth," Discover 14, no. 1 (January 1993): 67–68.

26. For more on SpectroLith technology: Barson D, Christensen R, Decoster E, Grau J, Herron M, Herron S, Guru UK, Jordán M, Maher TM, Rylander E and White J: "Spectroscopy: The Key to Rapid, Reliable Petrophysical Answers," Oilfield Review 17, no. 2 (Summer 2005): 14–33.

	AIT Induction Resistivity 90*	* Depth of investigation, inches	
	0.2 ohm.m 2,000		
	AIT Induction Resistivity 10		
Gamma Ray	0.2 ohm.m 2,000		
	AIT Induction Resistivity 20	Photoelectric Effect	
Caliper	0.2 ohm.m 2,000	0 20	
6 in. 16	AIT Induction Resistivity 30	Density Porosity	
Bit Size	0.2 ohm.m 2,000	0.4 ft³/ft³ −0.1	
6.3 in. 16.3	AIT Induction Resistivity 60	Neutron Porosity	
Washout	0.2 ohm.m 2,000	0.4 ft³/ft³ −0.1	

Organic-rich gas shale

Typical shale

^ Gas shale log. Gas shales are characterized by high gamma ray activity, high resistivity, low bulk density and low photoelectric effect compared with normal shales.
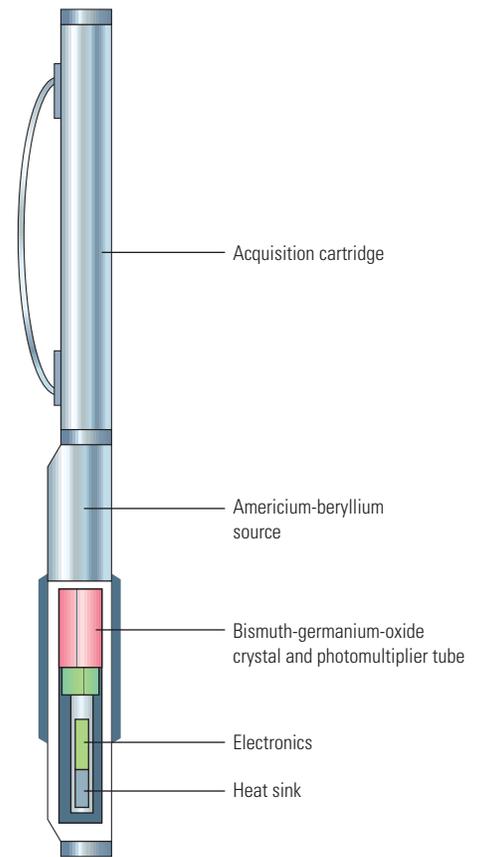
^ ECS Elemental Capture Spectroscopy tool. The ECS sonde records and analyzes the gamma ray spectra induced by neutron interactions with the formation. From these measurements, accurate estimations of formation components, including clay, carbonate, anhydrite, quartz, feldspar and mica, can be obtained.

- Acquisition cartridge
- Americium-beryllium source
- Bismuth-germanium-oxide crystal and photomultiplier tube
- Electronics
- Heat sink

teeth.[25] Owing to the popularity of vitrinite reflectance, these other indicators are often correlated to *Ro* values.

Other shale properties can be estimated from well logs, which in some cases, produce distinctive signatures (above). High gamma ray activity is thought to be a function of kerogen in the shale. Kerogen generally creates a reductive environment that drives the precipitation of uranium, which influences the gamma ray curve. Resistivity may be high because of high gas saturations, but varies with fluid content and clay type. Bulk densities are often low because of clay content and the presence of kerogen, which has a low specific gravity of 0.95 to 1.05 g/cm³.

Well logs are also used to ascertain the complex mineralogy of a shale and to quantify the amount of free gas in the pores of the source rock. Using a combination of conventional triple-combo and geochemical logs, Schlumberger petrophysicists can determine the organic carbon content of the shale and calculate for adsorbed gas. Geochemical logs also enable petrophysicists to differentiate types of clays and their respective volumes, information critical for calculating producibility and for determining which fluid to use during subsequent hydraulic fracturing treatments.

In the Barnett Shale and beyond to other basins, the ECS Elemental Capture Spectroscopy sonde and Platform Express integrated wireline logging tool are being used in conjunction with advanced interpretation techniques to calculate gas saturations and gas in place, and to characterize lithology. The ECS sonde uses neutron-induced, capture gamma ray spectroscopy to measure elemental concentrations of silicon, calcium, sulfur, iron, titanium, gadolinium, chlorine, barium and hydrogen (above).

These data are used with interpretation techniques such as SpectroLith lithology processing of spectra from neutron-induced gamma ray spectroscopy tools. The SpectroLith technique generates a log that displays the clay, quartz-feldspar-mica, carbonate, and pyrite or anhydrite fractions of the formation.[26] The elements used in SpectroLith processing do not occur in kerogen; hence, the lithology is

accurately represented but does not include the organic matter. By contrast, the logs measured with a Platform Express tool are affected by kerogen. For example, the gamma ray activity for kerogen is generally quite high because of the presence of uranium in a reductive environment, as described previously. Relying only on the gamma ray log to quantify clay would result in an overestimation of clay content. However, using the combination of ECS and Platform Express inputs will limit the potential for lithologic errors and allow for quantification of kerogen and porosity through differences between ECS and Platform Express measurements (below).

The Barnett Shale montage shows the integration of logging data, lithology and mineralogy interpretations and fluid evaluations. This montage of ECS and Platform Express measurements helps the operator to quantify gas in place and determine where to place perforations based on mineralogy and permeability. The interpreted mineralogy and porosity are also helpful in planning where to land lateral wellbores. In some areas, operators use the mineralogy curve to identify quartz, calcite or dolomite in the shale. These minerals increase

formation brittleness, thereby improving fracture initiation in horizontal wells.

These analyses form the basis for maps showing stratigraphy, kerogen maturity, and temperature versus depth. When complemented by mud-log evaluation and petrophysical analysis, this information helps geoscientists characterize variability in kerogen maturity and explore for locations where commercial gas accumulations may exist. After drilling begins, newly acquired drill cuttings or cores are tested to evaluate shale mineralogy and organic content.

Evaluating Gas in Place

Long-term shale-gas production at economic rates depends primarily on the volume of gas in place, completion quality and matrix permeability. Gas in place is often the critical factor for evaluating the economics of a play, and can take precedence over matrix permeability and completion quality.

Extensively developed basins, in which shale gas represents the current endgame in production, usually offer a plethora of data from field studies and previously drilled wells. Therefore, prior to drilling new wells, historical records such

as outcrop sections, geological field maps of organic-rich shales and data from earlier wells can be instrumental in developing preliminary estimates of shale gas in place. In particular, mud logs from earlier wells point to gas shows encountered at depth and record chromatographic analysis and flame ionization detector readings of the gas, in addition to lithology. Formation cuttings, which are customarily sieved, washed and dried before being collected in sample envelopes, are often retained for future analysis. When available, these cuttings can be sent for laboratory analysis of organic content and maturity.

During the early stages of a gas shale drilling campaign, coring will play a significant role in a formation-evaluation program. Shale cores provide direct measurements that geoscientists use to determine gas in place.

Gas is contained within pore spaces and fractures, or attached to active surface sites on the organic matter contained within a shale (next page). Together, this combination of interstitial gas and adsorbed gas make up the total gas content of a shale. By ascertaining proportions of interstitial and adsorbed gas under reservoir conditions, geoscientists can calculate gas in place using a variety of techniques.

Starting at the wellsite, freshly cut core is prepared for shipment to a core-analysis laboratory. Segments of this core may be sealed in canisters and sent to specially equipped laboratories for canister desorption tests. These tests measure the volume and composition of gas released from the core as a function of time. Canister desorption measures total gas, but does not measure proportions of adsorbed and interstitial components, or assess their pressure dependence. Therefore, other measurements must be brought into play.

Laboratory personnel place finely crushed shale into a sample chamber, then pressurize it. Holding the sample chamber at constant reservoir temperature, analysts can develop adsorption isotherms that establish realistic PVT relationships for the shale gas (see "The Langmuir Isotherm," *page 44*).

Another specialized technique for analyzing low-permeability, low-porosity formation samples was developed by TerraTek, a Schlumberger company.[27] The proprietary pyrolysis technique,
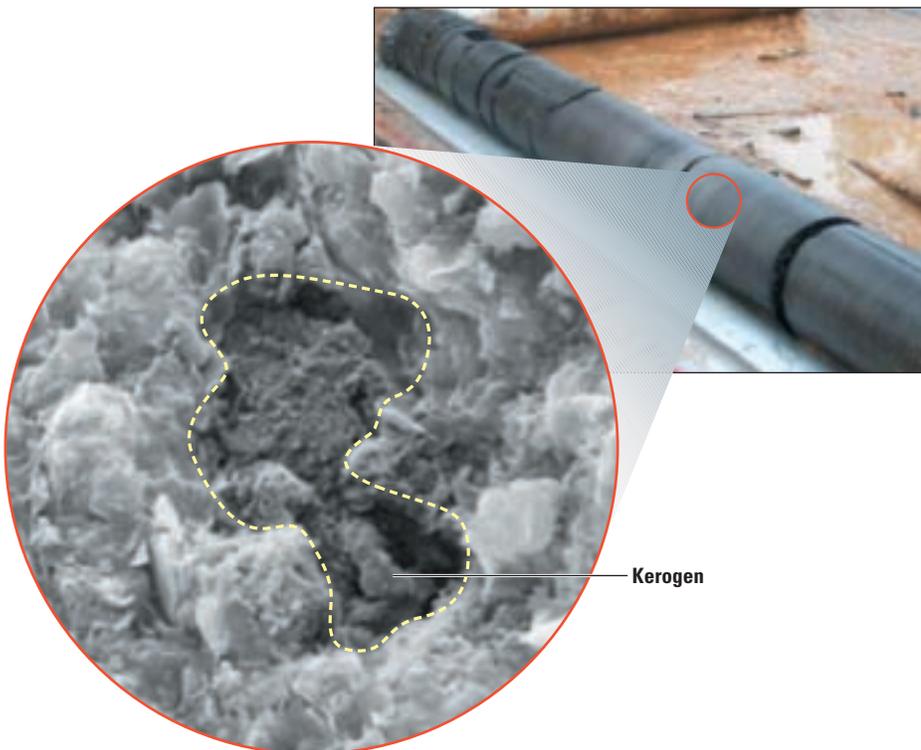
^ Scanning electron microscope photograph of kerogen in shale. The presence of organic matter contributes to the accumulation of hydrocarbons in shales in the form of adsorbed gas on surface-active sites within the porous organic matter. The kerogen also creates mixed-wettability conditions of the shale matrix, whereby shale regions close to kerogen sites are predominantly oil wet, and regions away from kerogen sites are water wet. (Photograph courtesy of Barbara Marin, TerraTek.)

Kerogen

27. The TerraTek facility in Salt Lake City, Utah, has been established as the Schlumberger Geomechanics Laboratory Center of Excellence.
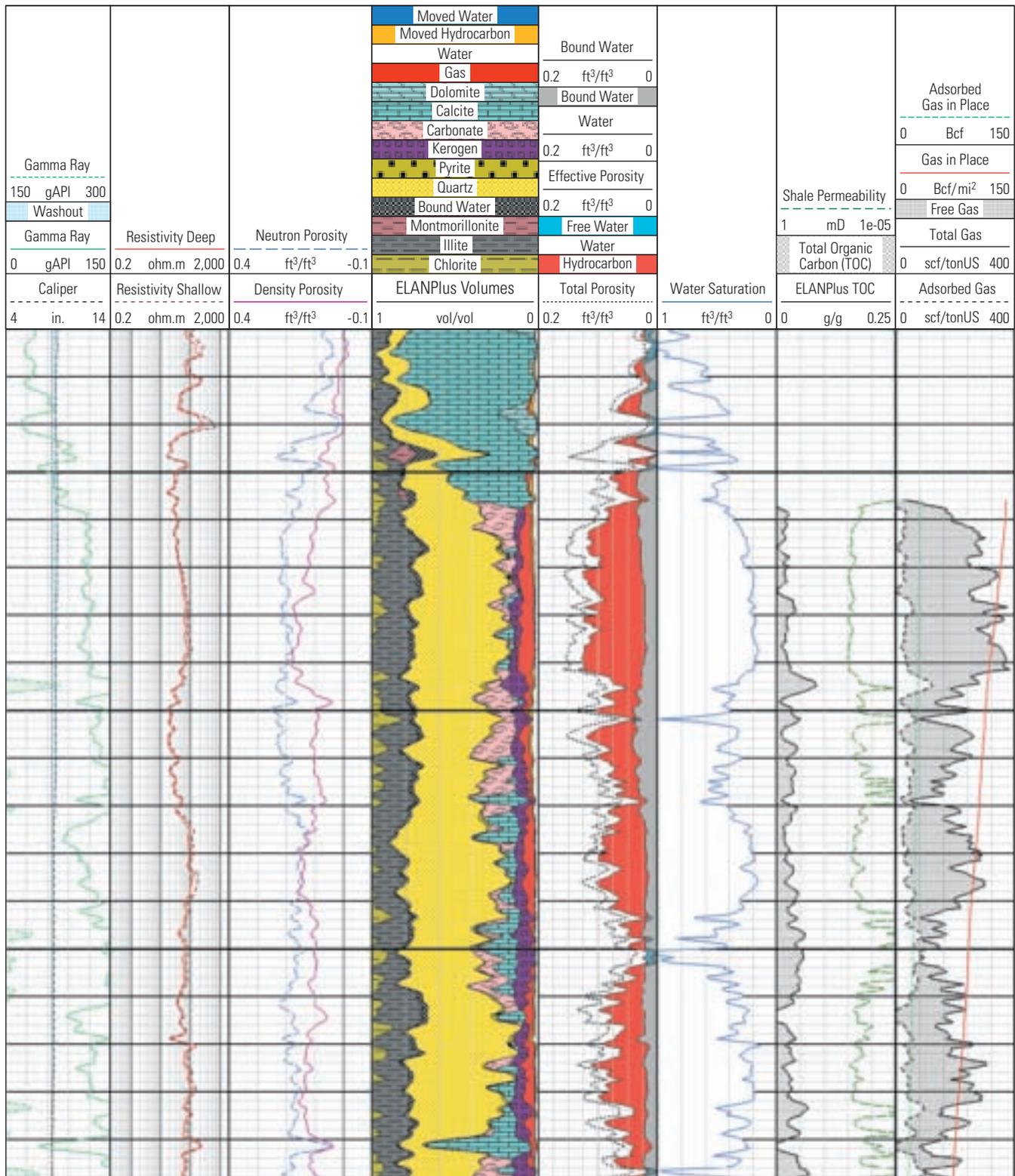
^ Montage of Barnett Shale log data derived from Platform Express and ECS logs. The first three tracks present measurements from the Platform Express tool. Track 4 presents results of a generalized gas shale petrophysical model based on Platform Express and ECS data that have been processed through ELANPlus advanced multimineral log analysis. This program helps to quantify mineralogy, kerogen and gas-filled and water-filled porosity. The remaining tracks quantify total and effective porosity, water saturation, TOC content, matrix permeability, gas in place and cumulative gas. Gas in place and cumulative gas values are calculated for both free and adsorbed gas. Track 4, in particular, illustrates some of the factors that underlie the success of this shale-gas play. In addition to kerogen content and gas-filled porosity, the Barnett Shale contains significant amounts of quartz and carbonates, which make the formation more brittle, and thus easier to fracture. Clay mineralogy is also dominated by illite, which tends to be relatively nonreactive to stimulation fluids.

known as Tight Rock Analysis (TRA), provides comprehensive evaluation of gas shale samples (next page, top).

Adsorption isotherm measurements allow a direct evaluation of the maximum adsorption capacity of gas by organic matter, as a function of reservoir pressure.[28] TRA gas-filled porosity measurements provide a direct measurement of interstitial gas as a function of reservoir pressure. When combined with canister desorption measurements, adsorption isotherms and TRA gas-filled porosity provide a complete description of gas in place. This information provides critical inputs for reservoir modeling, and indicates the relative contributions of interstitial and adsorbed gas to the induced-fracture system, as a function of drawdown and depletion.

Experience gained through core analysis has shown that mature, thermogenic shales are predominantly saturated by interstitial gas, with a fraction of adsorbed gas that varies from 50% to 10%. By contrast, immature, biogenic shales are predominantly saturated by adsorbed gas with smaller amounts of interstitial gas. Also, various proportions of water, gas and mobile-oil saturations occupy the pore spaces of shales.

The best reservoir-quality shales typically contain reduced oil and water saturations, high interstitial gas saturation and thus higher relative permeability to gas. Correspondingly, these shales have moderate to high organic content, a high degree of organic maturation, and texture that reflects a preservation of porosity and permeability during burial. Thus, to evaluate gas in place, laboratory measurements must provide direct evaluation of gas and liquid saturations, porosity, matrix permeability, organic content and maturation, as well as the capacity of the organic matter to adsorb gas at a constant reservoir temperature as a function of reservoir pressure.

Finally, log analyses, particularly when calibrated to actual measurements of reservoir properties supplied through core analysis, provide the basis for reliable predictions of gas in place through porosity and gas-saturation calculations. Log-based models can also be used to predict properties in adjacent wells across regions of limited lateral extent, thus facilitating the evaluation of basin-scale heterogeneity.

The Langmuir Isotherm
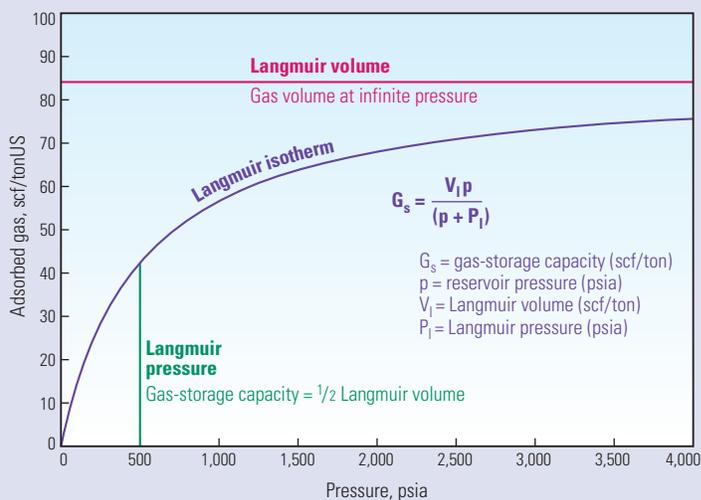
^ Adsorbed gas storage. The Langmuir isotherm (blue) shows the quantity of adsorbed gas that a saturated sample will contain at a given pressure. Decreasing pressure will cause the methane to desorb in accordance with behavior prescribed by the blue line. Gas desorption increases in a nonlinear manner as the pressure declines. Thus, in this example, a sample at 3,500-psi [24.2-MPa] pressure will have about 74 scf/ton adsorbed methane. As pressure first decreases from this point, the amount of gas desorbed is relatively small. Once the pressure has declined to 500 psi [3.4 MPa], one-half of the total gas that this shale could adsorb will have been desorbed. The remaining volume will desorb over the final 500 psi.

Methane adsorbed to the surface of kerogen is in equilibrium with free methane in the shale. The Langmuir isotherm was developed to describe this equilibrium at a specific, constant temperature. Two parameters describe this relationship: Langmuir volume, which describes the gas volume at infinite pressure; and Langmuir pressure, which is the pressure at which gas content equals one-half the Langmuir volume.

Langmuir parameters are measured through core analysis, using a sample of crushed shale that is heated to drive out adsorbed gases. The sample is subsequently placed in a sealed vessel and subjected to increasing pressure in a methane atmosphere at a constant temperature. The quantity of gas sorbed at constant temperature and increasing pressures is measured and used to create the isotherm by fitting the results to the Langmuir formula (above).

In shales that follow a similar curve, adsorption is a very efficient mechanism for storing gas at low pressures (less than 100 psi); by contrast, it is not efficient at high pressures, as sorbed gas approaches its asymptote at greater than 2,000 psi [13.8 MPa].

Evaluating Reservoir Potential
Evaluating the reservoir potential of a gas shale involves weighing positive or negative contributions from a variety of factors, including shale mineralogy and texture, clay maturity, kerogen type and maturity, fluid saturation, adsorbed and interstitial storage mechanisms, burial depth, temperature and pore pressure. In particular, porosity, fluid saturation, permeability and organic content are important for determining

28. Measurements can be conducted with a single gas, usually methane, or with a gas mixture that is representative of the mixture obtained by analysis of the produced gas.
29. Schenk, reference 2.

Sample Number	Bulk Density	Grain Density	Dry Grain Density	Porosity	Water Saturation	Gas Saturation	Mobile Oil Saturation	Gas-Filled Porosity	Bound Hydrocarbon Saturation	Bound Clay Water	Permeability	TOC
				% of bulk volume	% of pore volume	% of pore volume	% of pore volume	% of bulk volume	% of bulk volume	% of bulk volume		
	g/cm^3	g/cm^3	g/cm^3								nD	wt %
1	2.48	2.622	2.645	6.65	15.16	81.4	3.43	5.42	0.5	6.21	270	3.77
2	2.436	2.559	2.584	6.26	18.5	76.44	5.05	4.79	1.29	7.03	230	6.75
3	2.48	2.633	2.652	6.87	15.43	83.9	0.66	5.77	0.5	6.8	270	3.36
4	2.327	2.487	2.509	7.74	13.09	83.02	3.87	6.43	0.73	6.67	347	7.41
5	2.373	2.539	2.558	7.58	11.17	85.92	2.9	6.52	0.34	2.63	359	5.95
6	2.461	2.605	2.63	6.87	16.26	80.42	3.32	5.53	0.99	7.19	298	5.04

^ TerraTek Tight Rock Analysis technique. Specialized core measurements characterize grain density, porosity, fluid saturations, permeability and TOC of gas shales. In this particular dataset, gas saturation, porosity and permeability measurements indicate good reservoir potential.

whether a shale shows potential for further development (right).

Reservoir evaluation is complicated by the fact that shale gas is produced from formations that are notoriously heterogeneous. Shale qualities can vary abruptly in vertical and lateral directions, with intervals of high reservoir potential juxtaposed to sections of poorer quality. And reservoir-quality shales may expand or pinch out laterally, within relatively short distances, while gross shale thickness remains unchanged. Characterizing reservoir quality and understanding the underlying depositional and environmental causes of local heterogeneity thus pose fundamental challenges to the exploration and production of shale-gas reservoirs.

Geologists evaluate heterogeneity at a wellbore scale by analyzing cores and well logs. Shale typing by petrological analysis of drill cuttings, complemented by TOC measurements and log analysis from multiple wells, allows preliminary evaluation of reservoir potential within a basin. Through analysis of these measured data, geoscientists can determine gas in place, reservoir potential, and its variability as

a function of depth. These data form the basis for estimating the potential for economic production, identifying reservoir units to be targeted for completion, and developing cost-benefit assessments of lateral and vertical completions.

The greatest limit to gas production from shale may lie in the pore throats of the rock. TerraTek researchers have compared well productivity to matrix-permeability values over a variety of shale types and basins. Empirical evidence from these studies suggests that permeabilities below 100 nanodarcies define a lower limit to economic production of shale-gas plays. This limit appears to be independent of completion quality and gas content.

Ultimately, the key to finding gas shale reservoirs lies in pinpointing the concurrence of favorable geologic parameters such as thermal history, gas content, reservoir thickness, matrix rock properties and fractures.[29]

Developing the Reservoir

To produce gas to surface, rock must contain pathways sufficient to promote migration of the gas into a wellbore. In shales, low permeability of

Parameter	Minimum Value
Porosity	>4%
Water saturation	<45%
Oil saturation	<5%
Permeability	>100 nanodarcies
Total organic content	>2%

^ Critical reservoir parameters. Experience in multiple US shale-gas basins has shown that shale-gas reservoirs must meet or exceed these parameters to be commercially viable.

the rock matrix can be compensated somewhat through permeability caused by fractures in the source rock. Operators who target shales for production must therefore consider system permeability; that is, the combined permeability of a shale's matrix and its natural fractures.

To expose more wellbore to the reservoir and take advantage of natural fractures in a field, operators are turning increasingly to horizontal drilling (below). This technique, though not new to the industry, has been instrumental in

Bedding plane

Bedded pyrite nodules

Bedded pyrite nodules

Natural fractures traversing the complete borehole

Transversely oriented drilling-induced fractures

Bedding plane
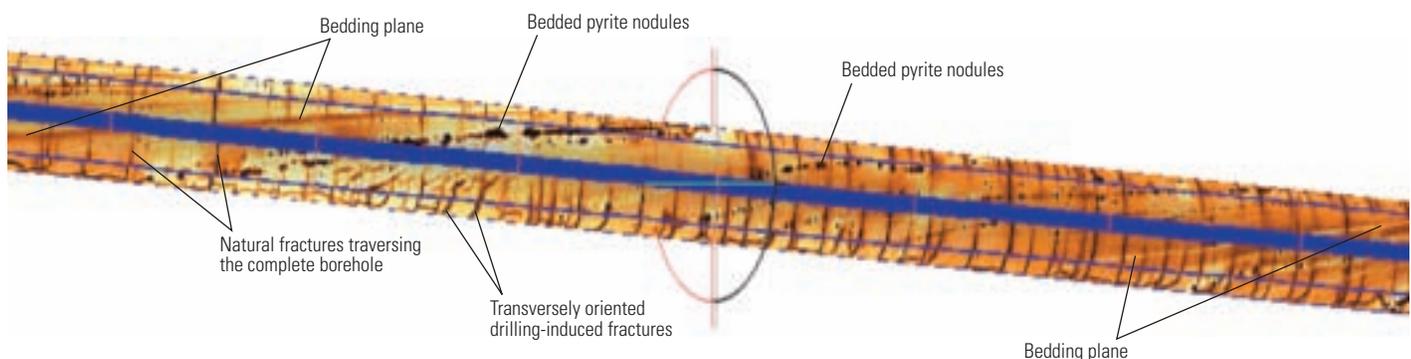
^ Drilling through fractures. The FMI Fullbore Formation MicroImager log shows fractures and bedding features encountered by a horizontal well. Drilling-induced fractures appear along the top and bottom of the well path, but stop along the sides of this wellbore, where stress is highest. Preexisting natural fractures penetrated by the wellbore appear as vertical lines that cut across the top, bottom and sides of the wellbore. Darker pyrite nodules are quite distinctive, and are seen running parallel to bedding planes.

expanding the success of shale-gas developments. The role of horizontal drilling is clearly demonstrated by the growth of development in the Barnett Shale in the Fort Worth basin of north central Texas. Starting with a vertical well drilled by Mitchell Energy in 1981, it took 15 years to surpass 300 wells in this play. In 2002, Devon Energy, after acquiring Mitchell, began drilling horizontal wells. By 2005, more than 2,000 horizontal wells had been drilled. Furthermore, experience in the Barnett Shale has shown that horizontal wells in this play attain approximately three times the EUR of vertical wells, for only about twice the cost.[30]

Other technologies have been vital to developing the play. Using 3D seismic interpretation, operators are better able to plan horizontal wellbore trajectories. This technology has helped operators expand the Barnett Shale play into areas previously thought unproductive due to a water-bearing, karsted Ellenburger dolomite that underlies the shale in many areas.

Operators generally seek to open up more of the shale surface area to production by drilling perpendicular to the direction of maximum horizontal stress, thereby increasing the likelihood of crossing fractures. However, conventional directional drilling techniques can be hampered by torque and drag, which are generated by sliding and rotating as drillers build inclination and azimuth in their wellbores. In more ambitious well trajectories, torque and drag can limit lateral reach and make it difficult to log the well. Rotary steerable systems have been used to circumvent these problems while producing straighter, less tortuous wellbores.[31] In some cases, inclination varies by less than 0.5° from heel to toe.[32]

To address the problem of logging in horizontal wells, LWD assemblies, such as the geoVISION imaging-while-drilling service, have been employed in some wells. This tool produces resistivity images and wellbore formation-dip analysis along the length of the wellbore. Imaging logs can provide structural, stratigraphic and mechanical-property information for optimizing subsequent well completions. For example, imaging enables comparison of natural formation fractures to drilling-induced fractures, helping the operator determine optimal targets for perforating and stimulating the well. In the Barnett Shale play, images from these logs are used to identify subseismic faults and associated swarms of natural fractures known to produce water from the underlying karsted Ellenburger dolomite.[33]
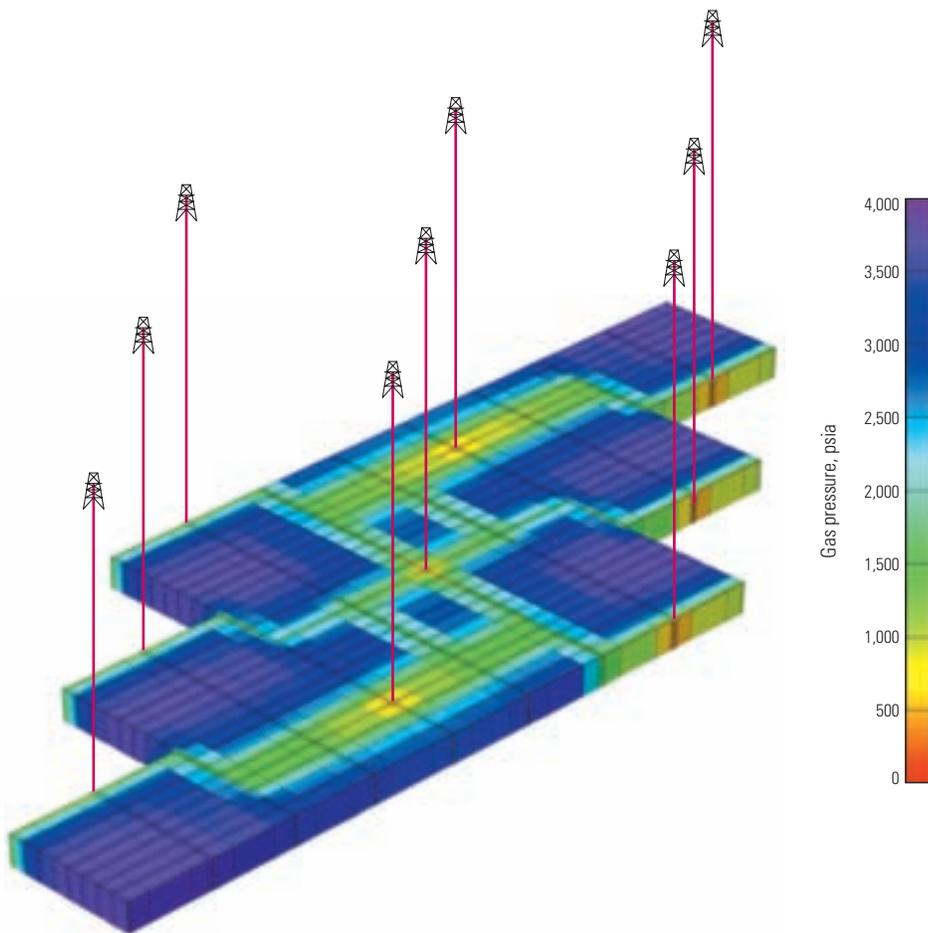
^ ECLIPSE reservoir simulation. The modeled shale horizon is color-coded to show pressure-depletion trends after 15 years of production from nine vertical gas wells. Hydraulically induced and naturally occurring fractures produce a web of interconnected pathways through which gas is produced from the formation to the wells.

For infill-drilling applications, borehole images are helpful in identifying hydraulic fractures from offset wells. This allows operators to focus stimulation treatments on parts of the reservoir that have not been fractured previously. The presence and orientation of drilling-induced fractures, or the absence of such fractures, can prove useful in ascertaining variability in stress and mechanical properties along the length of the lateral wellbore. This information has helped reduce completion difficulties and associated costs in the Barnett Shale.[34]

Shale Reservoir Simulation

Most reservoir simulators model conventional gas reservoirs, where gas is stored in a single-porosity system. Gas shales require a different approach. Finite-difference simulators, such as the Shale Gas module in ECLIPSE reservoir simulation software, consider the gas stored in pore spaces within a tight shale matrix, the gas adsorbed on organics within a shale, and the free gas contained in natural fractures within the shale formation.

30. Waters G, Heinze J, Jackson R, Ketter A, Daniels J and Bentley D: "Use of Horizontal Well Image Tools to Optimize Shale Reservoir Exploitation," paper SPE 103202, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, September 24–27, 2006.

31. For more on rotary steerable systems: Williams M: "Better Turns for Rotary Steerable Drilling," *Oilfield Review* 16, no. 1 (Spring 2004): 4–9.

32. In a directional well, the heel is found between the vertical and horizontal sections of the well, while the toe lies at the other end of the horizontal section.

33. Waters et al, reference 30.

34. Waters et al, reference 30.

35. Slickwater treatments use a low-viscosity, water-base fluid to transport proppant into hydraulically created fractures.

36. Waters et al, reference 30.

These reservoir simulators allow operators to incorporate everything they know about the rock as they build single-well and full-field models of their reservoirs. Reservoir characteristics such as net-pay thickness, reservoir pressure, temperature, gas content, water saturation, natural fracture geometries, matrix porosity, TOC and methane adsorption isotherm functions can be easily factored into the models. With this information, operators can estimate gas in place for their reservoirs.

Matrix permeability measurements and hydraulic-fracture geometries resulting from post-stimulation modeling and microseismic interpretation can also be incorporated into the model. Bulk system permeability can be estimated by utilizing the model to calibrate to observed gas and water production. By building a model that accurately matches actual well production performance, the operator can predict estimated ultimate recovery for an area (previous page).

Reservoir simulation is particularly important for its capacity to perform various types of sensitivity analyses. These analyses include optimal well design, weighing horizontal versus vertical trajectories; optimal stimulation design, regarding number and size of treatments; and optimal drilling patterns, based on different spacing scenarios. These analyses provide operators with the opportunity to make future development decisions on the basis of science, engineering and economics.

Shale Stimulation

Natural fractures, while beneficial, usually do not provide permeability pathways sufficient to support commercial production in gas shales. Most gas shales require hydraulic fracturing.

Fracturing exposes more shale to the pressure drop provided by a wellbore. With closely spaced hydraulic fractures in the shale along a horizontal lateral wellbore, gas can be produced even faster.

Operators frequently pump low-viscosity, water-base slickwater fluid and proppant treatments in moderately deep, high-pressure shales, typically found at depths between 5,000 to 10,000 ft [1,524 to 3,048 m].[35] In shallower shales or those with low reservoir pressures, nitrogen-foamed fracturing fluids are commonly pumped. The fluid, pumped under high pressure, fractures the shale. These fractures can extend through the shale for a thousand or more feet beyond the wellbore. In theory, the grains of proppant wedge into the fractures, holding them open once pumping has stopped.

In the Barnett Shale, stimulation treatments have evolved throughout the life of this play, starting with small CO_2 or N_2 foam treatments performed on the lower Barnett until the mid-1980s.[36] Operators then began employing massive hydraulic fracturing treatments (below). These treatments averaged 600,000 galUS [2,270 m^3] of crosslinked gel and 1,400,000 lbm [635,000 kg] of sand proppant. Despite boosting EUR, high completion costs and low gas prices resulted in marginal economics for the play. Operators continued to perform massive fracs until 1997, when Mitchell Energy began

^ Barnett Shale massive frac job. In this single-stage stimulation treatment, more than 100 frac tanks full of water have been trucked in and arranged along the perimeter of the wellsite. Pumping units, manifolds and monitoring equipment are placed around the wellhead near the center of the site. As completion processes evolve, fewer resources are now required. The wellbore is now divided into small intervals and stimulated in multiple stages. The newer approach has improved well performance and reduced completion costs.
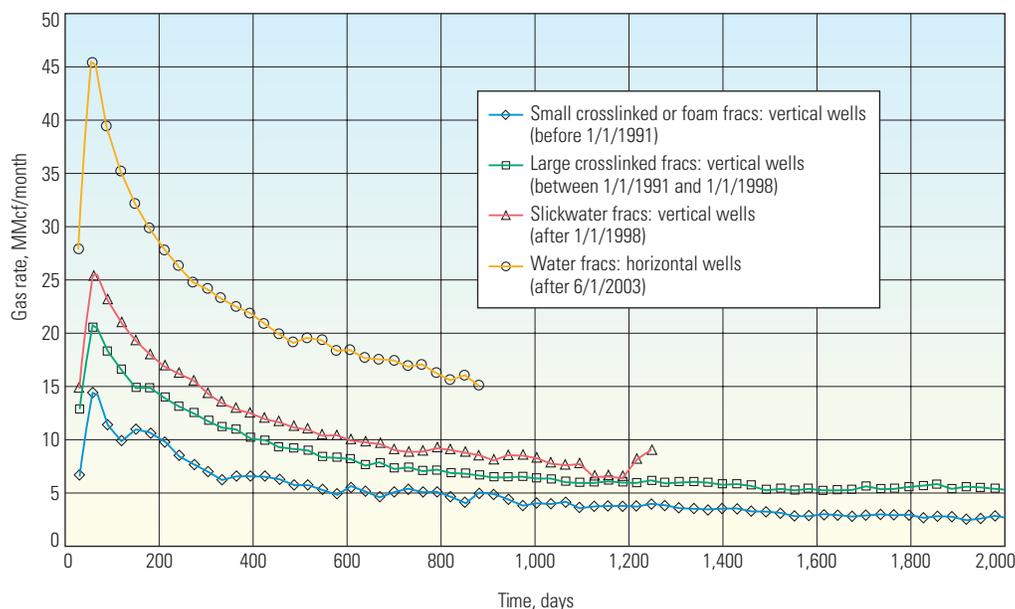
^ Improved performance with evolving technology. As drilling and fracturing technology evolved over the years, operators in the Barnett Shale saw dramatic improvements over previously employed techniques.

evaluating slickwater stimulation treatments. These treatments establish long and wide fracture fairways using roughly twice the volume of the massive crosslinked fluid fracs, while pumping less than 10% of the proppant volume. Though well performance was slightly better than that of massive frac treatments, the stimulation costs were reduced by about 65%. These treatments have become the norm in the Barnett Shale (above). Furthermore, the reduction in stimulation costs allowed operators to complete the Upper Barnett intervals where present, thus improving EURs by roughly 20% or more.

Although water and sand are commonly used in frac jobs in the Barnett Shale, some operators in other plays find that not enough proppant has been transported into their induced fractures. During such fracturing jobs, the fluid might not create fractures wide enough to accommodate the grains of proppant. In other cases, grains pumped into a fracture quickly settle out of suspension from the fluid that transported them. In either case, the result is a smaller fracture that provides less permeability than intended.

To overcome these problems, some operators employ ClearFRAC polymer-free frac fluid or FiberFRAC fiber-based fracturing fluid

technology to keep the proppants suspended for extended periods of time. ClearFRAC fluids are used to transport proppant deep into fractures. Except for the proppant itself, the ClearFRAC fluid is free of solids that might reduce fracture permeability, and has been shown to be compatible with organic-rich shales.[37] Fibers contained in the FiberFRAC fluid keep proppant grains in suspension until the fracture closes onto the grains, locking them in place. The fibers eventually dissolve, increasing flow through the fracture. Both fluids keep proppant in the fractures as they slowly close down. Thus fractures stay open once the well is placed on production.

In the late 1990s, Mitchell began to experiment with additional stimulation treatments. Refracturing has been most successful in wells that were originally completed with gelled fluids. Microseismic monitoring indicates that these treatments are activating natural fractures normal to maximum horizontal stress.[38] This activation does not occur as often with viscous fluids, and refracturing in wells initially completed with slickwater treatments is generally less successful.

37. Fredd CN, Olsen TN, Brenize G, Quintero BW, Bui T, Glenn S and Boney CL: "Polymer-Free Fracturing Fluid Exhibits Improved Cleanup for Unconventional Natural Gas Well Applications," paper SPE 91433, presented at the SPE Eastern Regional Meeting, Charleston, West Virginia, USA, September 15–17, 2004.

38. For more on fractures and microseismic technology for monitoring fracture propagation: Bennet L, Le Calvez J, Sarver DR, Tanner K, Birk WS, Waters G, Drew J, Michaud G, Primiero P, Eisner L, Jones R, Leslie D, Williams MJ, Govenlock J, Klem RC and Tezuka K: "The Source for Hydraulic Fracture Characterization," Oilfield Review 17, no. 4 (Winter 2005/2006): 42–57.

39. Anderson BI, Barber TD, Lüling MG and Sen PN: "Observations of Large Dielectric Effects on Induction Logs, or, Can Source Rocks be Detected with Induction

Measurements?," Transactions of the SPWLA 47th Annual Logging Symposium, Veracruz, Mexico, June 4–7, 2006, paper OOO.

40. Permittivity is the degree to which a medium resists the flow of electric charge.

41. Faraj B, Williams H, Addison G, McKinstry B, Donaleshen R, Sloan G, Lee J, Anderson T, Leal R, Anderson C, Lafleur C and Ahlstrom J: "Gas Shale Potential of Selected Upper Cretaceous, Jurassic, Triassic and Devonian Shale Formations, in the WCSB of Western Canada: Implications For Shale Gas Production," Gas Research Institute Report GRI-02/0233, December 2002.

42. Curtis JB: "Fractured Shale-Gas Systems," AAPG Bulletin 86, no. 11 (November 2002): 1921–1938.
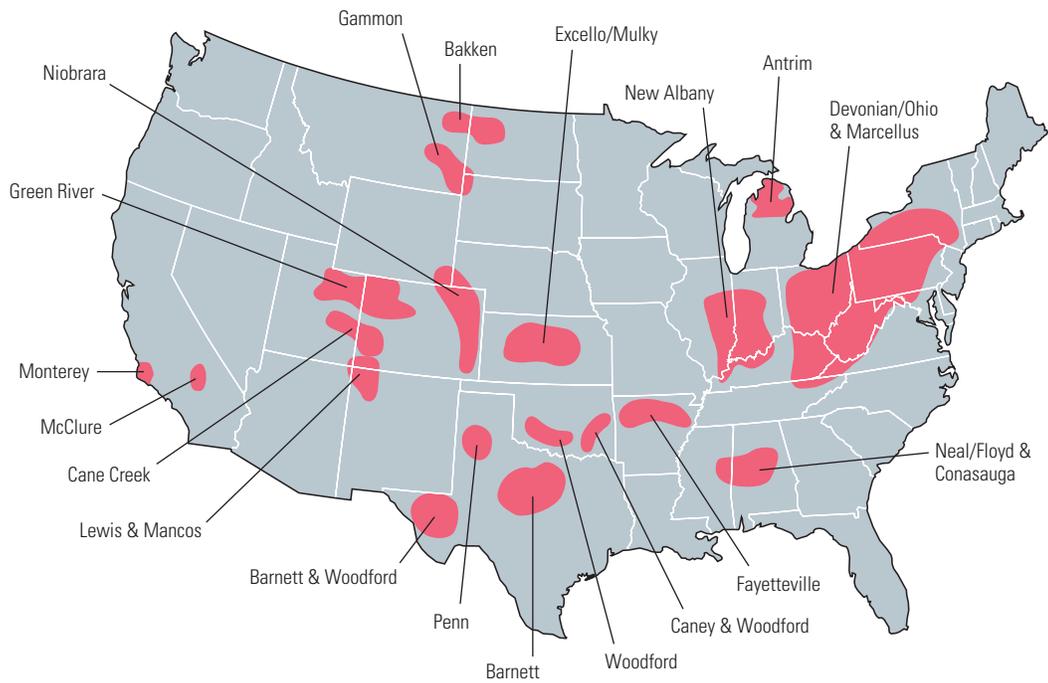
^ Organic-rich source-rock basins. This map shows major shale-gas basins in the United States with total resource potential of 500 to 1,000 Tcf [14.16 to 28.32 trillion m³].

In addition to rising gas prices and improved horizontal drilling techniques, the development of economic and efficient stimulation practices was key to the commercial success of gas shale wells.

Migration to Future Basins

New technologies, or new applications of proven technologies, will undoubtedly migrate from one basin to the next as word of their success spreads. One such application under study involves analysis of induction signals to find source rock.

Schlumberger researchers are currently investigating voltage measurements of induction logging tools.[39] One component of the conductivity signal, called the quadrature, or out-of-phase portion of the signal, is usually quite small. However, certain rock formations cause significant changes to this quadrature signal.

Examining raw data from AIT Array Induction Imager Tools, Schlumberger researchers observed large negative quadrature signals beyond the range normally expected from shale zones in the area. By contrast, adjacent sandstones and shales exhibit small, positive quadrature signals, typical of conductivity measurements in the area.

Testing and modeling of several possible contributors to quadrature-signal anomalies revealed that abnormally high dielectric permittivity was the only effect that could duplicate the large negative quadrature signals seen in those shales.[40]

Certain shale formations, known to be source rocks in Texas, Oklahoma and Utah, exhibit high dielectric permittivities, and are surrounded by nonsource-rock shales with low permittivities. The size of the clay platelets, in combination with the presence of pyrite, causes anomalously large dielectric permittivities and provides intergranular space for hydrocarbon generation.

Schlumberger researchers are investigating the extent to which these electrical character-istics vary between source and nonsource shales. With further testing and refinements, insights from ordinary induction logs may prove useful in correlating the quadrature signals of shale formations to their hydrocarbon-generating capacity.

Beyond the Fort Worth basin, other shale plays are found nearby in the Woodford and Caney shales in Oklahoma and the Fayetteville shale in Arkansas. Other organic-rich shales are scattered around the USA, and are being developed in the mature Illinois, Michigan and Appalachian basins, to name a few (above). As shale-gas production increases in the USA, operators in other countries will find analog basins that pave the way for increasing shale-gas reserves.

Outside the USA, basin studies are being conducted to look for similar potential. In western Canada, geologists are taking a closer look at the shale-gas potential of the Upper Cretaceous Wilrich, Jurassic Nordegg/Fernie and Triassic Doig/Doig Phosphate/Montney forma-tions of Alberta and British Columbia. Geochemical studies of these formations show potential for future development.[41] Currently, the scarcity of shale-gas plays outside of the USA may be due to uneconomical flow rates and extended well payouts rather than to an actual absence of productive shale-gas basins.[42] However, the experience gained in US basins will inevitably help operators around the world exploit shale resources as production from conventional resources reaches maturity. —MV