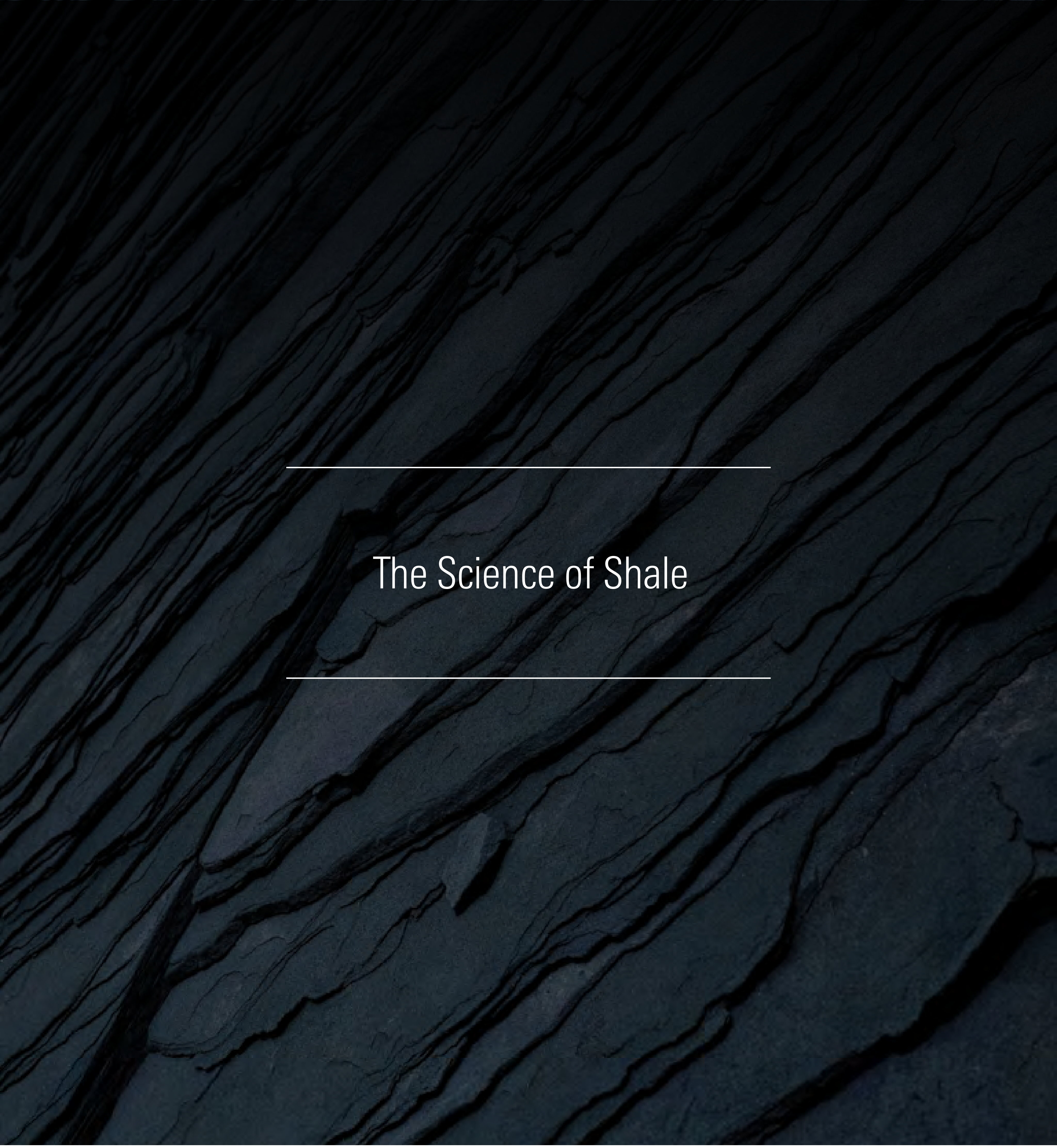


The Science of Shale

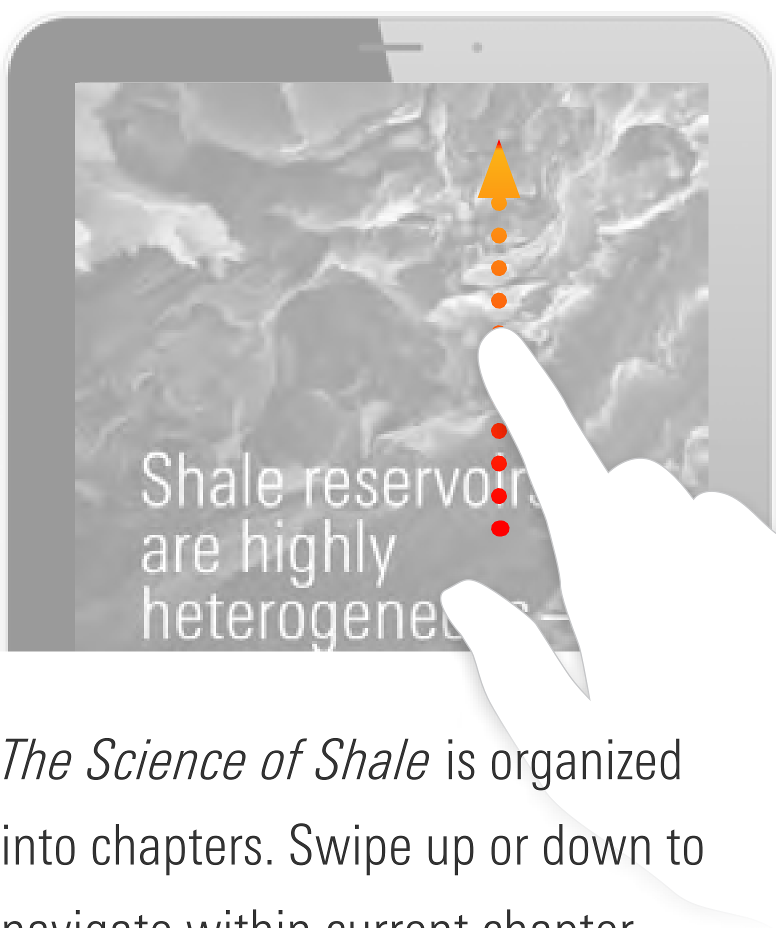
Help

Schlumberger

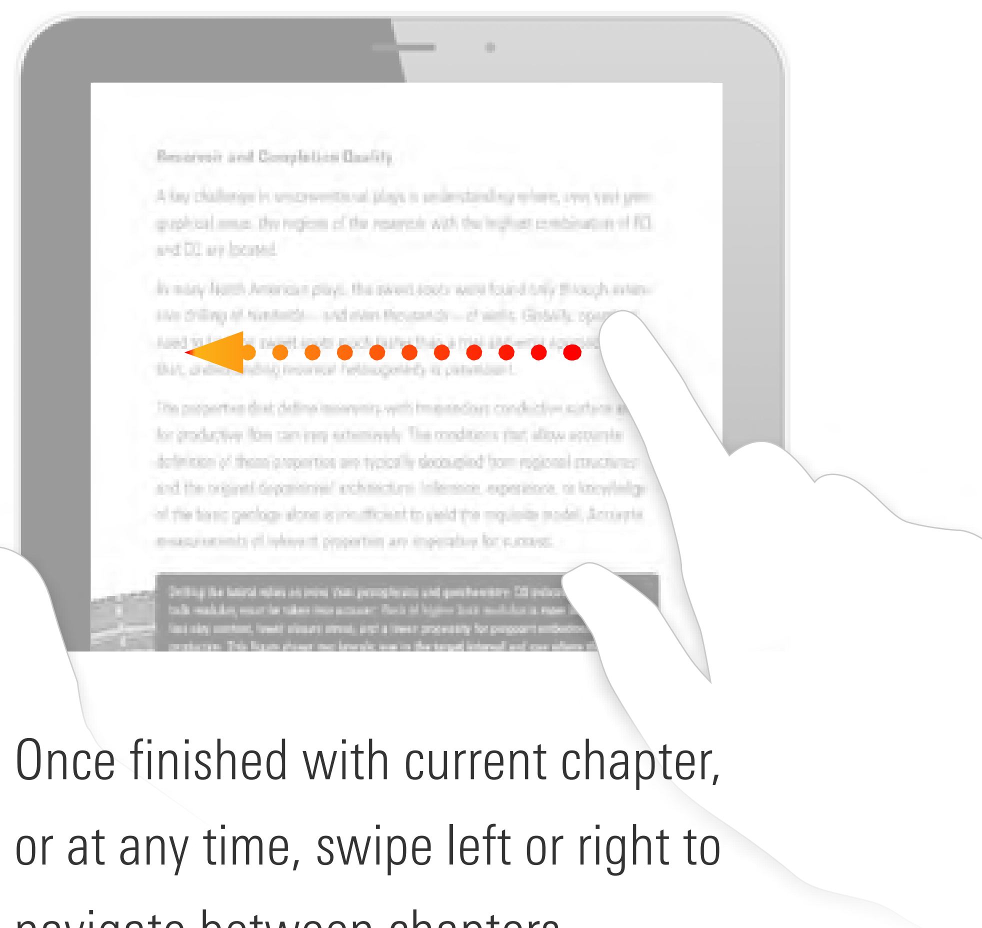
Start

The Science of Shale is an interactive look at the current state of unconventional reservoirs worldwide and synergy blah blah here's some pro tips and tricks and stuff to help use it.

Navigation

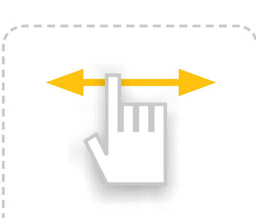


The Science of Shale is organized into chapters. Swipe up or down to navigate within current chapter.



Once finished with current chapter, or at any time, swipe left or right to navigate between chapters.

Interactivity



Helpful symbols (examples pictured) indicate page elements that can be interacted with. Scroll, swipe, or click accordingly and learn more.

A New Era

The days of “easy” oil are gone. With world energy consumption at an all-time high, all resources are required: solar, wind, water, nuclear, biofuels, and hydrocarbons. No one source can fulfill our growing demands.

Natural gas and liquids from characteristically complex unconventional plays—organic shale, tight gas and oil, coalbed methane—are transforming the global energy market. Advances in reservoir characterization, drilling, and completions technologies have turned these reservoirs from uneconomic source rocks into sought-after resources.

The great industry challenge is determining how to systematically convert the unconventional resource potential into commercial reserves—all while addressing safety, environmental, water, and land-use sustainability concerns. Improved scientific understanding of the unique characteristics of these formations is leading the way to a cleaner energy future.

A New Era

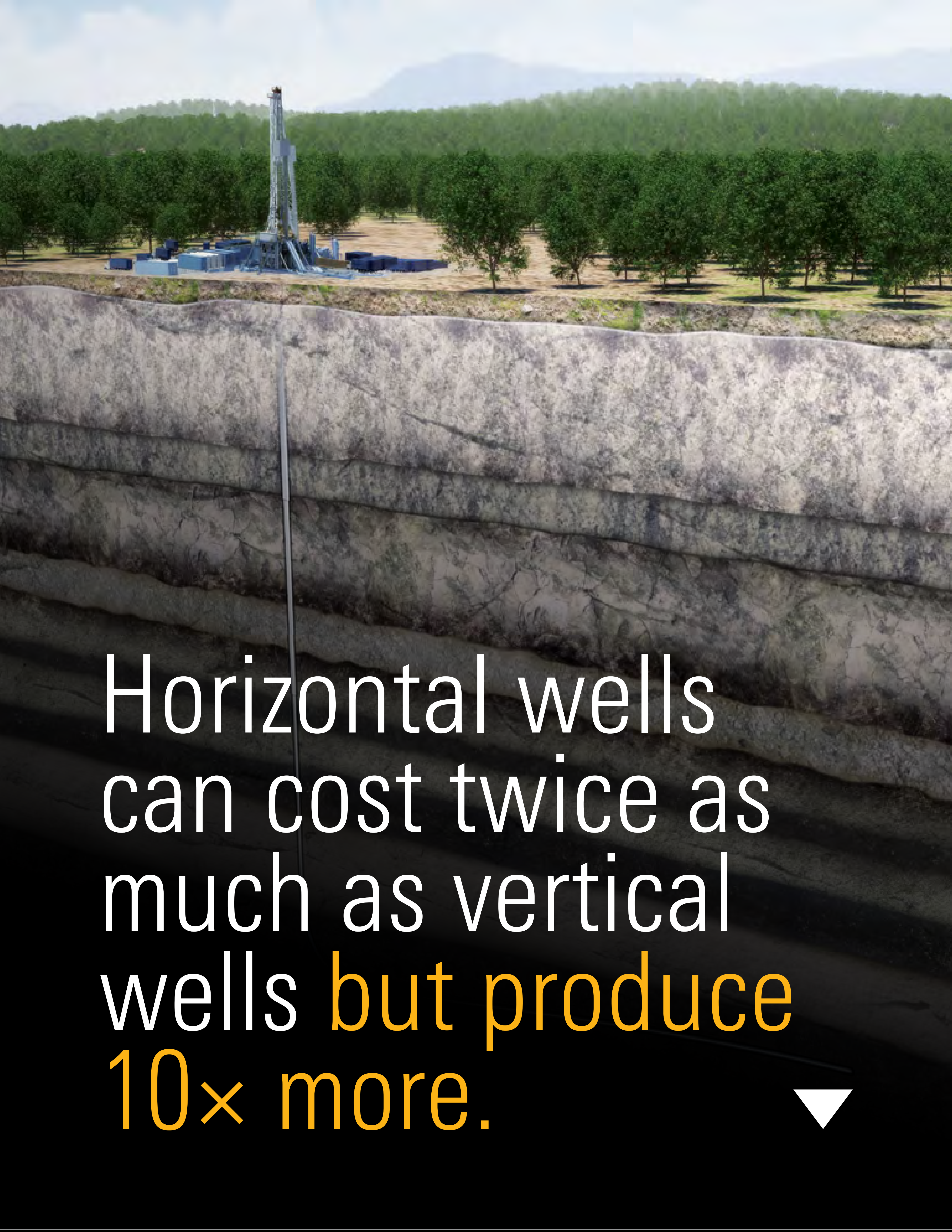
Although shale resource estimates will likely change over time, the initial estimate of technically recoverable shale gas resources in 41 countries is 7,299 trillion cubic feet (Tcf).† To put that into perspective, just 1 Tcf is enough to heat 15 million homes for a year.‡ For all shale, including liquids, conservative estimates for oil and gas resources exceed 2 trillion barrels of oil equivalent.

International Expansion

The shift to shale holds enormous potential for countries such as China, South Africa, and Argentina, which sit atop wide expanses of organic shale resources. Unconventional resource development will create millions of jobs and provide centuries of clean, domestic power. However, operators must first overcome completion quality challenges—and address infrastructure, land access, regulations, and the acceptance of hydraulic fracturing by local populations.

Shale Potential

All over the world, operators seek the vast oil and natural gas resources still residing within these ultralow-permeability organic mudstone sediments. The potential of shale is tremendous, but converting these resources into commercially viable reserves requires breakthrough technology and the right economic conditions. In this modern industrial age, we must provide affordable and plentiful energy for future generations—while extracting resources in a safer, more environmentally responsible manner.



Horizontal wells can cost twice as much as vertical wells but produce 10× more.

Conventional oil and gas discoveries are becoming more and more scarce, increasing the need to develop unconventional resources. Understanding the complex mineralogy, variable rock fabric, and anisotropic mechanical properties poses the greatest challenge in finding and producing these resources. Once the reservoir is properly understood, appropriate drilling, completion, and production strategies can be applied to successfully convert it into economic reserves.

Permeability to the Nanodarcy Range

Unconventional reservoirs often have permeabilities well below that of tight gas reservoirs and porosity numbers in the single-digit range. Economic extraction can be obtained only by creating an enormous, conductive fracture flow area in rock with high reservoir quality (RQ) and completion quality (CQ).

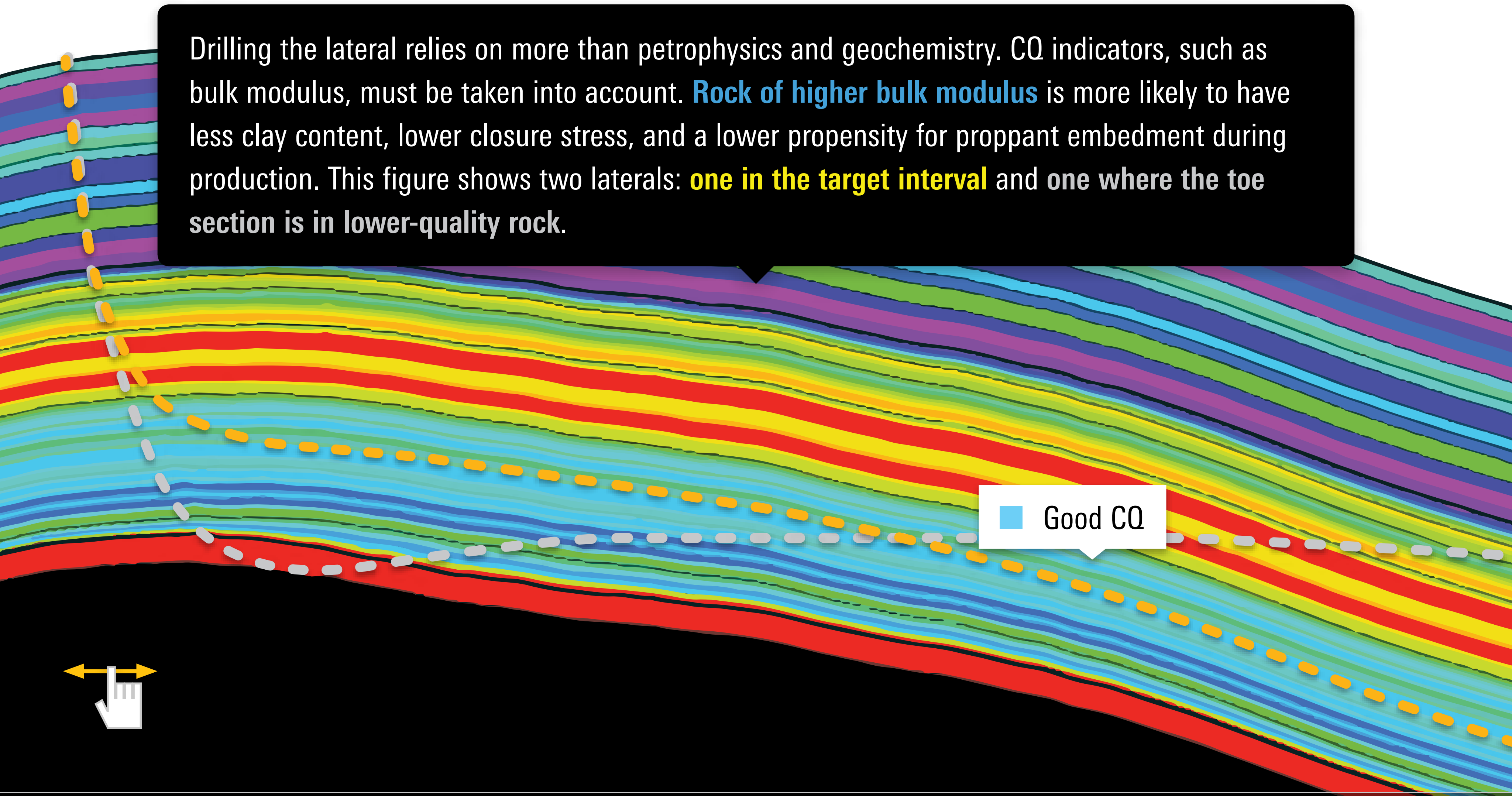
Almost all unconventional wells must be hydraulically fractured in multiple stages. Smart reservoir characterization techniques, multistage completion technologies, and advanced modeling tools are improving the efficiency of drilling and completion operations.

Reservoir and Completion Quality

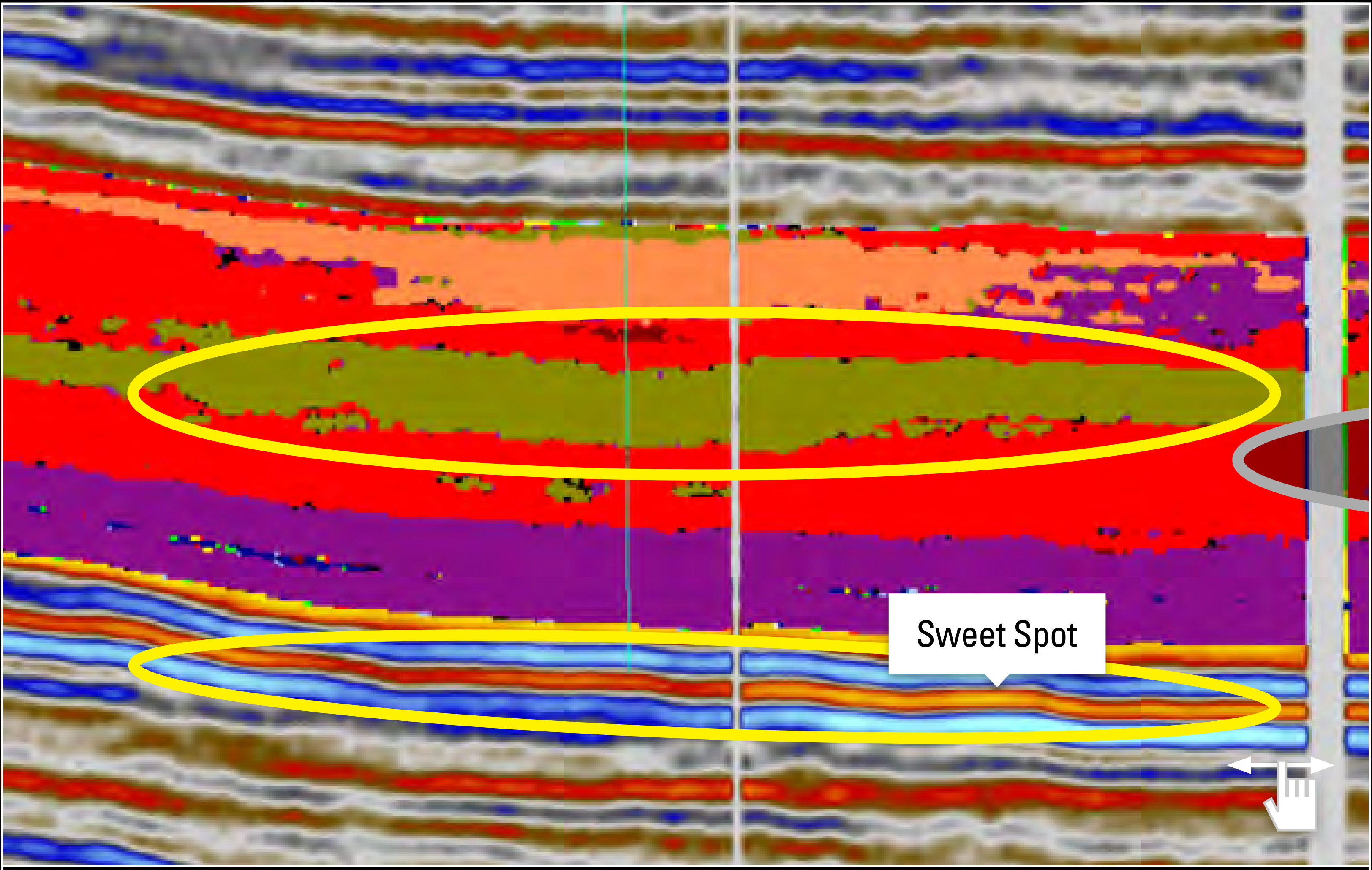
A key challenge in unconventional plays is understanding where, over vast geographical areas, the regions of the reservoir with the highest combination of RQ and CQ are located.

In many North American plays, the sweet spots were found only through extensive drilling of hundreds—and even thousands—of wells. Globally, operators need to find the sweet spots much faster than a trial-and-error approach. To do that, understanding reservoir heterogeneity is paramount.

The properties that define reservoirs with tremendous conductive surface area for productive flow can vary extensively. The conditions that allow accurate definition of these properties are typically decoupled from regional structures and the original depositional architecture. Inference, experience, or knowledge of the basic geology alone is insufficient to yield the requisite model. Accurate measurements of relevant properties are imperative for success.



Drilling the lateral relies on more than petrophysics and geochemistry. CQ indicators, such as bulk modulus, must be taken into account. **Rock of higher bulk modulus** is more likely to have less clay content, lower closure stress, and a lower propensity for proppant embedment during production. This figure shows two laterals: **one in the target interval** and **one where the toe section is in lower-quality rock.**



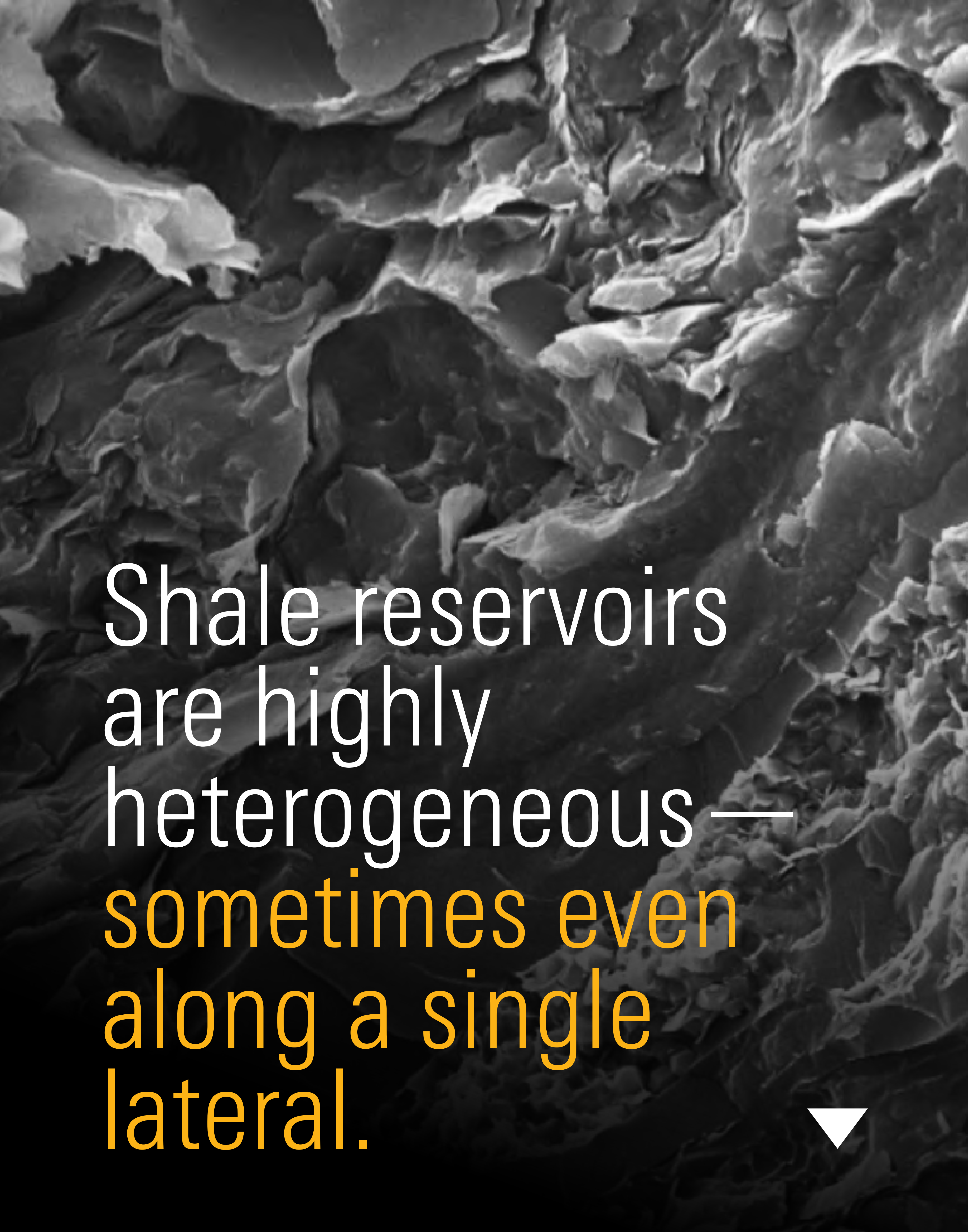
Finding the Sweet Spots

Completing nonproductive rock is costly and does not contribute to recovery. Geological data, such as core analysis, well logs, and seismic surveys, pinpoint the most prospective source rock and determine the best way to extract its contents.

Seismic data are the ideal way to understand between-well variability in heterogeneous systems such as unconventional reservoirs. Seismic data provide an effective means to propagate core measurements and observations across a seismic volume. Core data are linked to log data, and log data are linked to seismic volumes via classification.

Spotlight on China

The US Energy Information Administration (EIA) estimates that China has 1,115 Tcf of technically recoverable shale gas, making it the world's largest shale gas resource. Still in the early exploration phase, China must find a way to develop these resources despite challenges such as hilly terrain, high population density, limited transportation, and constrained water supply. It has set an ambitious goal of producing more than 2,000 Bcf/year—a staggering 6% of its energy needs—by 2020.



Shale reservoirs are highly heterogeneous — sometimes even along a single lateral.

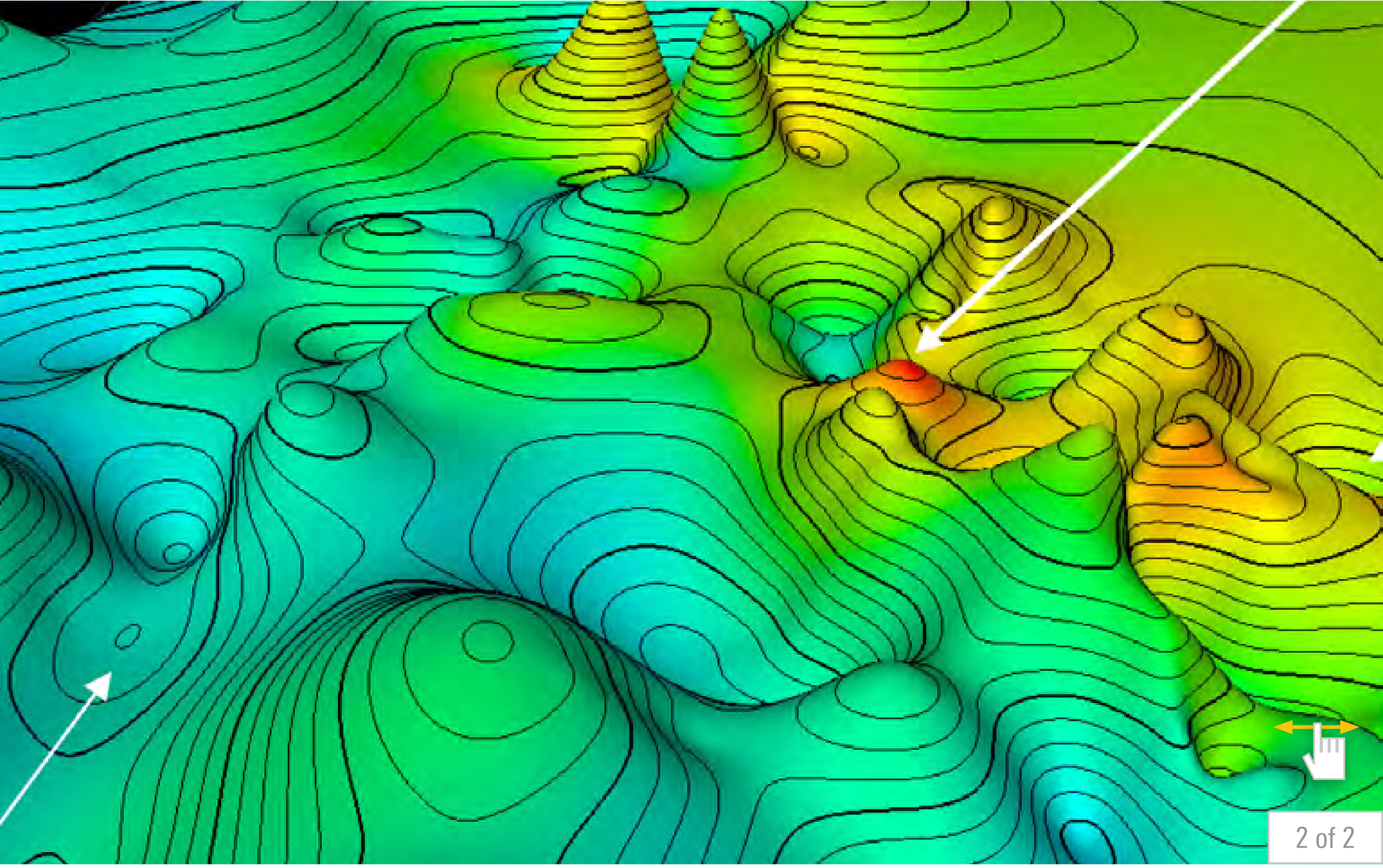
Deposited in low-energy environments with high organic content, high-surface-area shale particles undergo significant diagenesis over time. This leads to large-scale heterogeneity. Burial, subsidence, uplift, faulting, and other geological processes are part of the basinal history leading to present-day conditions. Diagenesis of the organic matter intermixed in sediments will often substantially modify the quality of the deposits, contributing to a wide areal disparity in reservoir potential.

Data at Seismic, Well Test, Log, and Core Scales

To understand and quantify heterogeneity, measurements are needed at various scales and locations. Beginning at the aeromagnetic, gravity, and seismic scale—data in the range of tens of meters' resolution—gross layering, faulting, and other structural features are determined. Elastic mechanical properties can often be calculated, leading to some understanding regarding potential completion quality effects, including height containment. Techniques to determine or infer regions with a higher intensity of natural fracturing help better describe the reservoir flow capacity.

Dynamic pressure transient tests provide an additional scale of reservoir measurement. Conventional drillstem tests are not possible in ultralow-permeability reservoirs, so low-rate pump-in and decline tests are used to characterize the rock on the scale of a few meters radius of investigation. When performed on multiple layers in a wellbore, accurate in situ stress numbers are determined and related to acoustic log velocities. On a larger scale, pressure drawdown modeling of the production stream yields values analogous to a pressure buildup test conducted in a conventional reservoir, once superposition effects from drawdown pressure are accounted for.

The small-scale measurements, which range from $\frac{1}{10}$ in to 2 ft, are correlated to logging measurements. Once properly calibrated, logs can be used to infer the formation characteristics at these different scales. For example, a dynamic effective permeability obtained from after-closure analysis (ACA) can be scaled to log-based permeability transforms with varying success. Core values of absolute permeability, determined with specialized techniques, are also scaled to log measurements. Seismic features are related to log measurements as well, so that the overall reservoir and completion characteristics can then be determined over a large volume—the ultimate goal being the creation of a heterogeneous earth model (HEM).



Heterogeneous Earth Model

The heterogeneous earth model is a 3D map of the reservoir and completion quality across the prospect. Measurements and geostatistical techniques are used to integrate log, seismic, and core information over the entire area under evaluation. By first using core to classify rock types in terms of reservoir and completion quality properties, then defining rock physics models for each type, this information can be related to logging tool measurements. Then, the log measurements can be used to condition seismic results and propagate the RQ and CQ properties across the subset area.

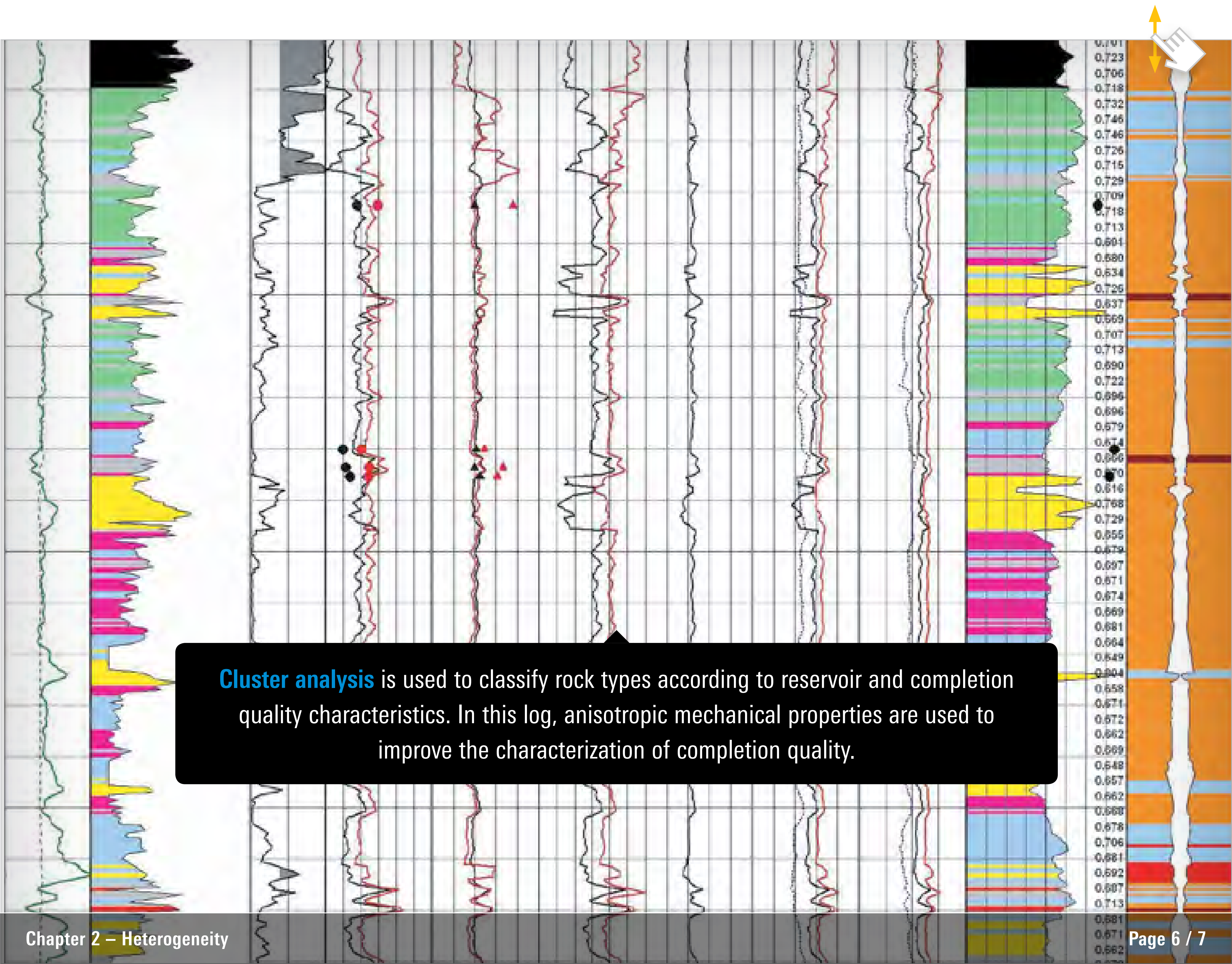
Shale Petrology

The heterogeneity seen in unconventional reservoir rocks is observed beginning at the core- and log-scale level. Scanning electron microscope (SEM), thin section, and core analysis techniques for ultralow-permeability rocks are used to quantify various features of the rock, including organic and mineral petrology, organic and inorganic content, type and degree of maturation, porosity types, permeabilities, fluid saturations, mechanical properties, and rock-fluid interactions. When repeated on several key wells for a given prospect, these core measurements can be related to logging tool responses. This introduces heterogeneity into geocellular models via the concept of rock types, which are classified according to reservoir, nonreservoir, and completion criteria.

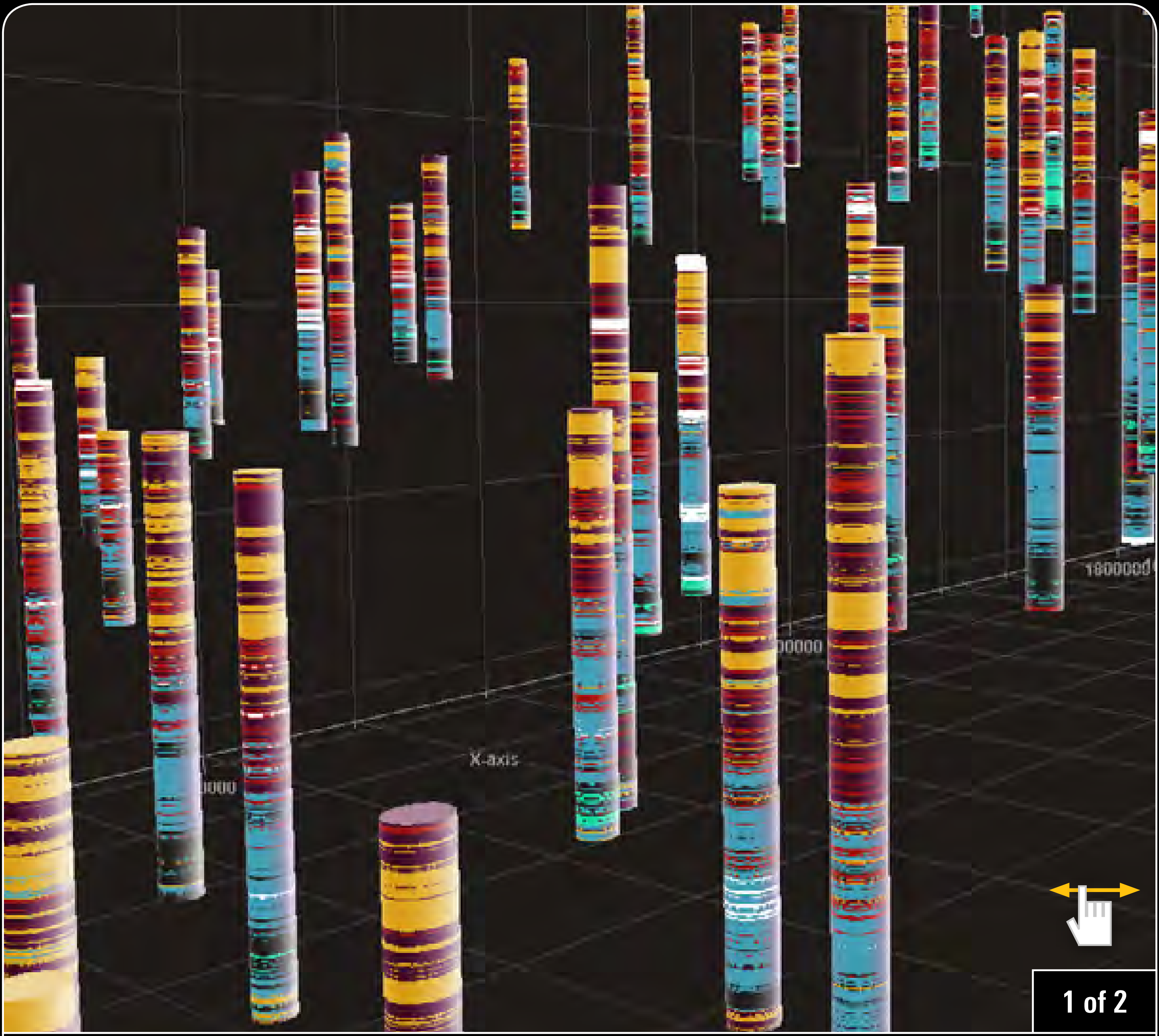
Specialized core testing apparatus for ultralow-permeability rocks uses pressure-decay testing to determine permeability via application of Boyle's law and helium porosimetry.

Geomechanics and Pore Pressure

Beginning in the laboratory, with representative core, anisotropic measurements of geomechanical properties are made. Correlations convert dynamic acoustic log measurements to static core measurements. At the field level, in situ stresses and pore pressures are distributed across the geological model and related to permeability and production performance. Numerical simulation of various completion scenarios links geomechanical effects and well performance. Sector models of well performance are scaled up to a multiwell response, allowing asset teams to make decisions on well spacing and location.



Cluster analysis is used to classify rock types according to reservoir and completion quality characteristics. In this log, anisotropic mechanical properties are used to improve the characterization of completion quality.



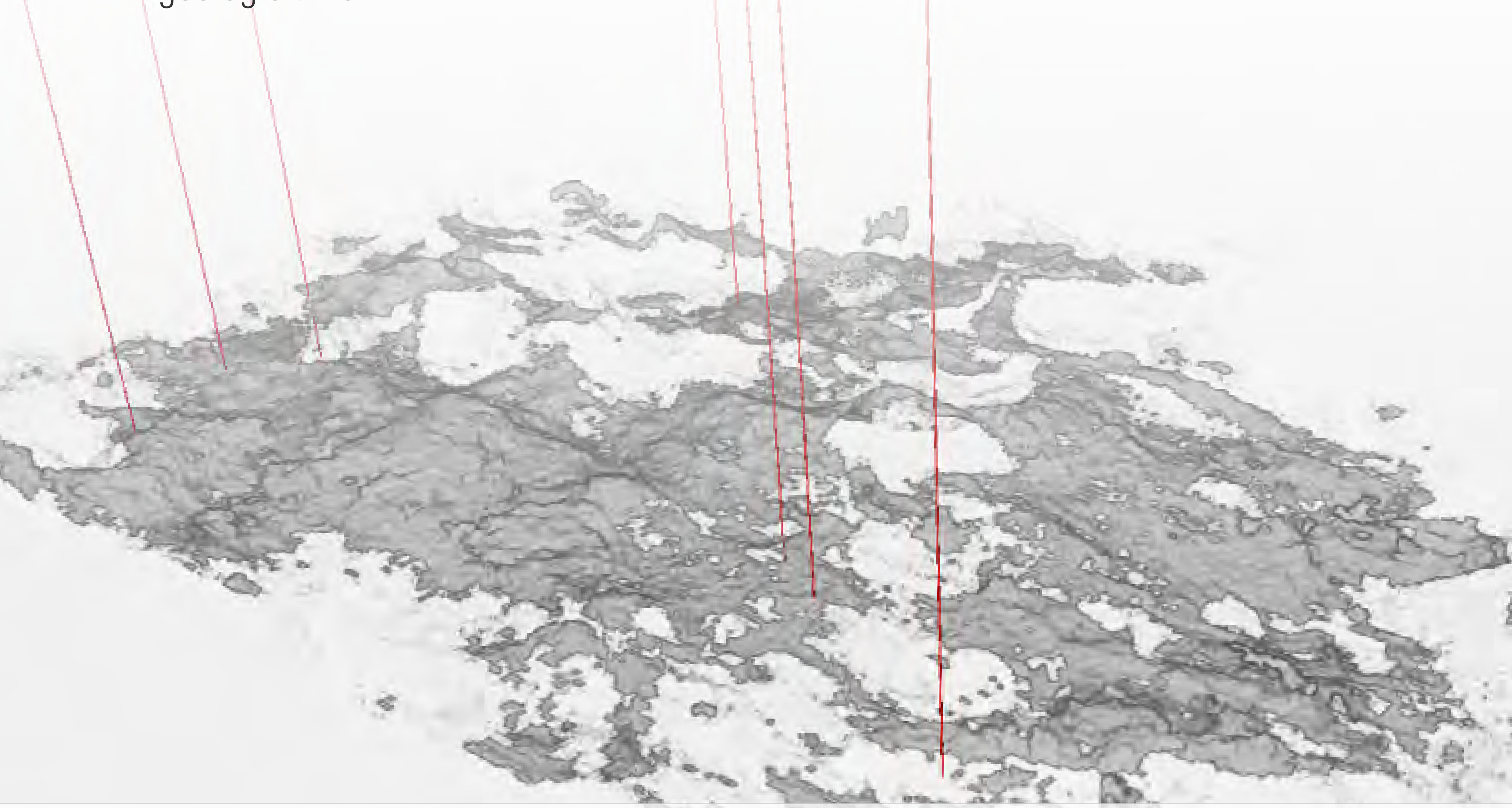
Heterogeneous Rock Analysis

The heterogeneity of unconventional reservoirs requires analysis of the spatial variability of material properties. Heterogeneous rock analysis provides measurements for evaluating sample-, core-, and log-scale heterogeneities. The analysis also optimizes core sampling selection for cost-effective representation of material properties.

The Bazhenov shale is larger than Mexico, Kuwait, and the United Kingdom—combined.

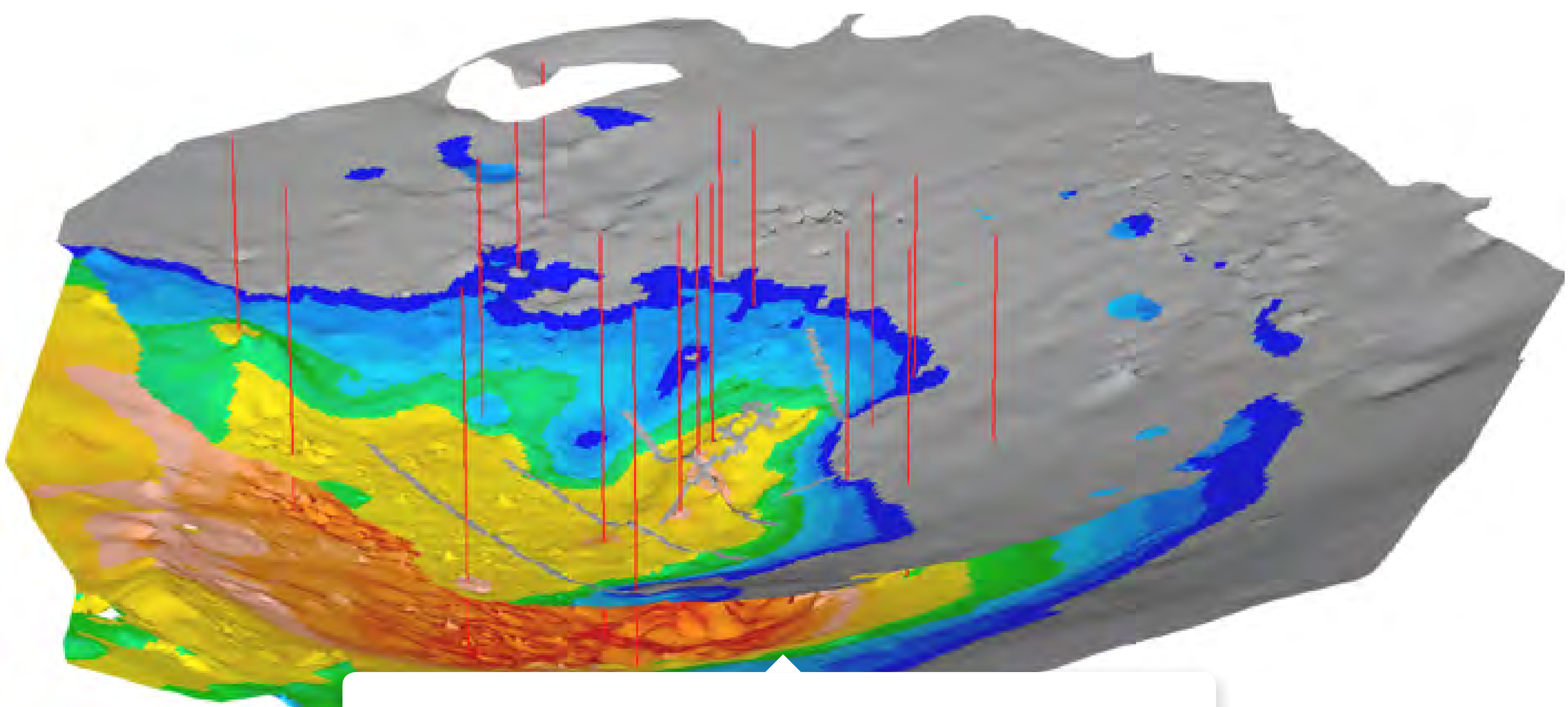
Economically productive organic-rich rocks must be in a state of thermal maturity, meaning that the solid kerogen in the rock has "cracked" to form oil or natural gas. In modeling the basinal history, this process can be simulated considering kerogen type, organic content, and the thermal history to determine where mobile hydrocarbons exist in sufficient quantities.

Seismic, well, and geological information are combined to model the history of a sedimentary basin, including postdepositional processes. This enables determining the source and timing of hydrocarbon generation, quantities, and types in the subsurface. These dynamic models provide a complete record of the structural evolution and temperature and pressure history, as well as the effects on generation, accumulation, and loss of oil and gas in a petroleum system through geologic time.

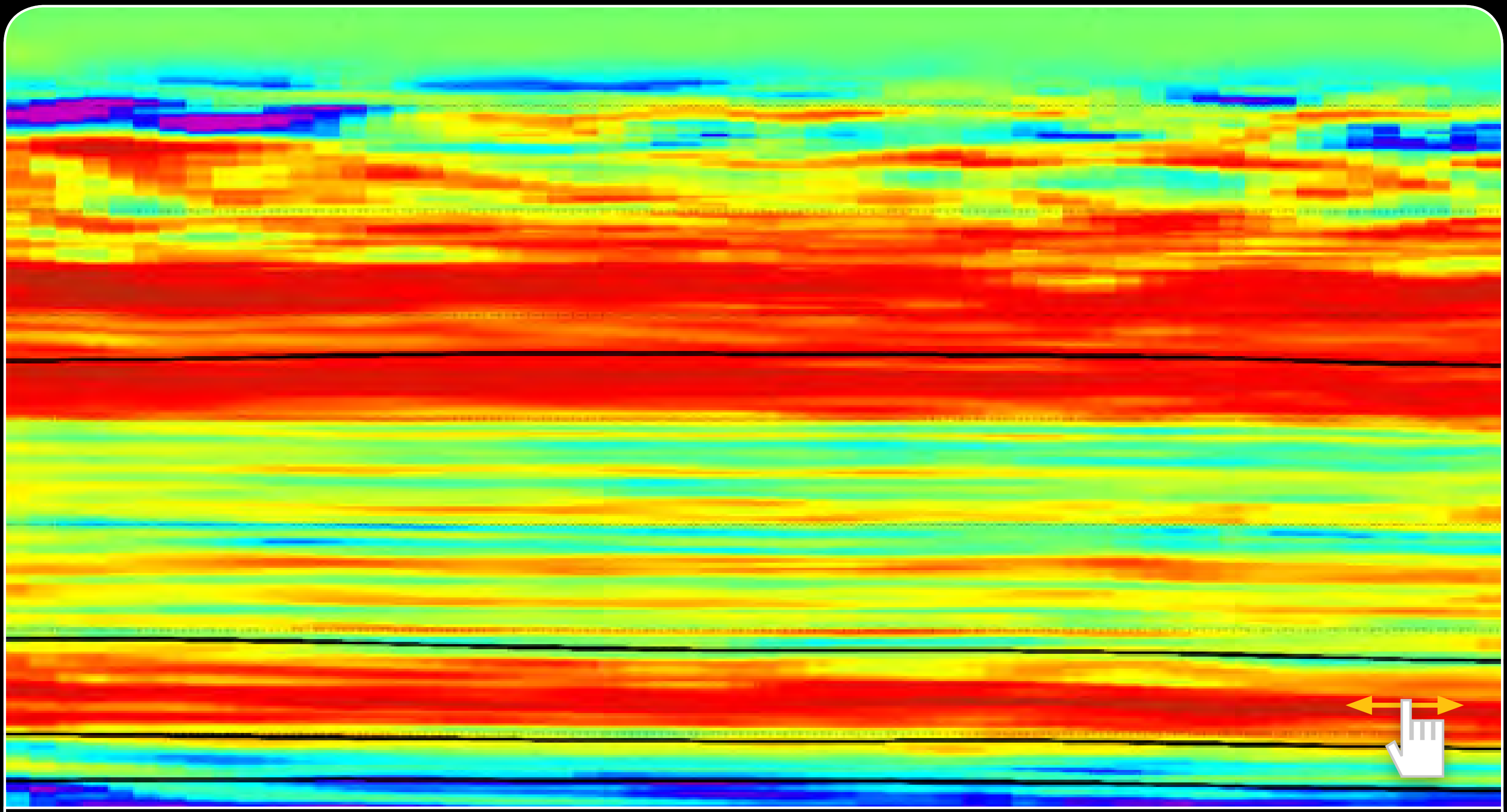


Petroleum Systems Modeling

The 3D petroleum systems model includes all the key elements of geological risk involved in exploration for an unconventional resource—sourcing and timing of hydrocarbon generation, maturation, potential migration, and loss—allowing prospects to be identified. Once key pilot wells are drilled and new data is collected, refinements are made to calibrate the model and improve confidence in the predictions.



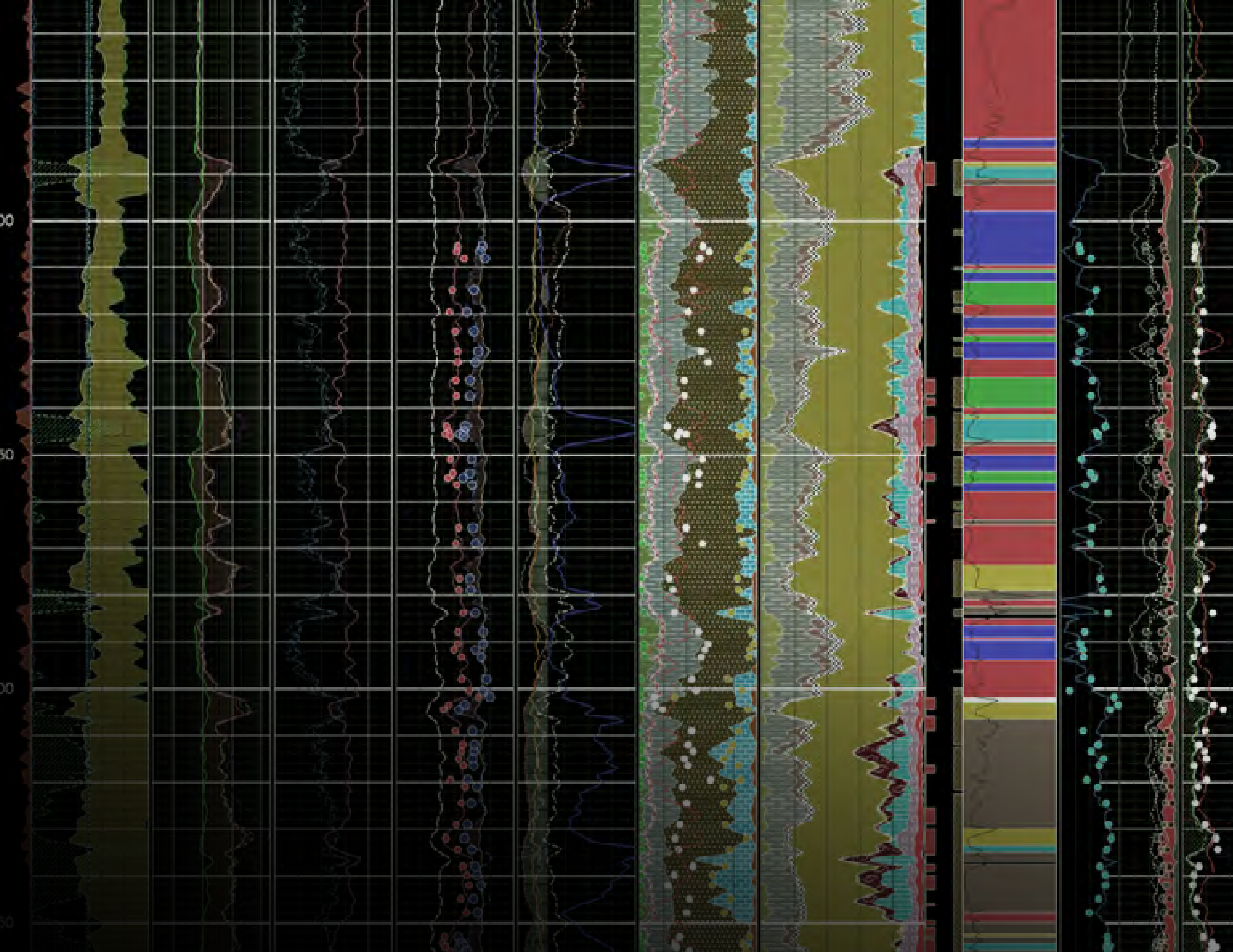
The **3D petroleum systems model** gives detailed hydrocarbon generation, migration, and composition information.



Seismic Surveys for Unconventional Resources

While often used for exploration, seismic data are crucial in the development process. Calibrated to well logs, borehole seismic data, and core measurements, surface seismic data identify key parameters, including rock and fluid properties, reservoir and completion quality, rock strength, fracture closure stress, fracture containment, and horizontal stress anisotropy. This helps improve field planning and reduce both drilling and completions time.

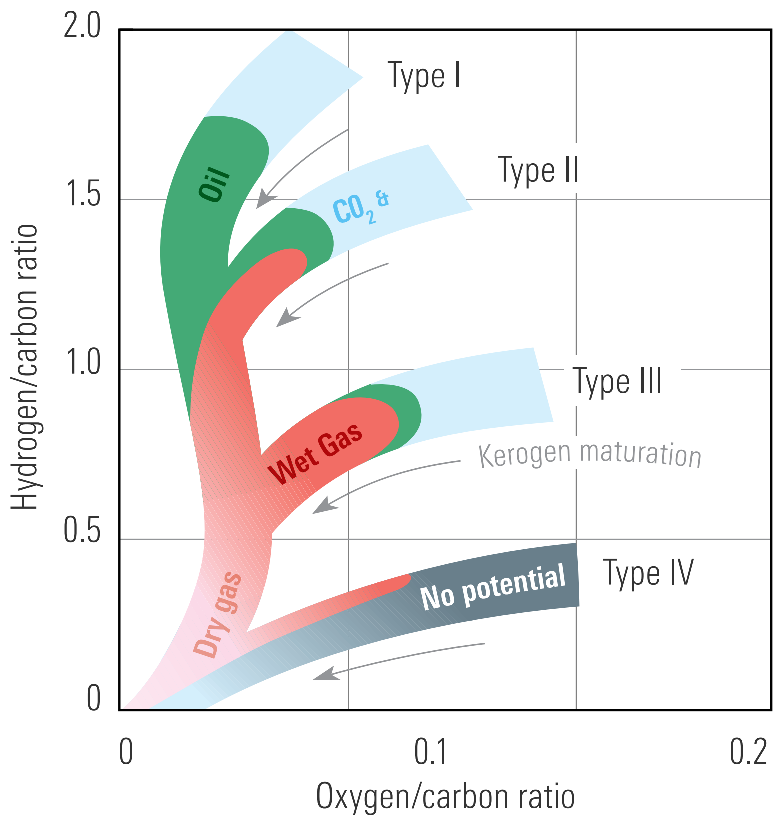
Integrated acquisition and processing reduces nonproductive time while enabling engineers to design current and future completions for specific target zones.



Shale is 10× to 100× less permeable than tight gas reservoirs

Reservoir quality captures the intrinsic productive capacity of the resource, including resource amount, kerogen concentration, free gas or liquids, permeability, pressure, and viscosity. As with a conventional reservoir, what is known about porosity, permeability, thickness, and pressure must be accurate. However, in unconventional reservoirs, it can be much more difficult to determine these properties.

Where porosity is below 7%, many conventional logging tools have difficulty determining total and effective pore space. Accurate permeability numbers are even more difficult to determine. Because the wells do not flow prior to hydraulic fracturing, buildup testing is impossible. Once fracturing treatments are performed, the wells must be shut in for months—or even years—to determine the unique formation properties. Therefore, new advanced core testing procedures are used to measure permeability, effective porosity, and saturations on sidewall and whole core samples. These measurements can be related to relative permeability values in simulators and then validated via production.



The Type I and Type II kerogens in most oil shales are not yet mature enough to generate hydrocarbons. **As these kerogens mature**—usually through geologic burial and the increased heat associated with it—they transform into oil, and then with more heat, to gas.

Determining Pressure

In shale, obtaining an accurate measure of pressure is challenging because buildup tests are not viable. Bottomhole pressure gauges, gauges on perforating guns, and shooting fluid levels also suffer from the inherent challenge of ultralow permeability. Given these obstacles, operators often locate the best porosity and permeability along a lateral section and perform a low-rate, low-volume pump-in test to break the rock. Following the injection, the created disturbance can be monitored for a few days or weeks to determine a value for pressure.

All of these parameters, including pressure-volume-temperature (PVT) properties, go into determining reservoir quality. The better the reservoir extent, hydrocarbon content, permeability, and pressure are, the better the play's potential. Creating maps of RQ across a given play helps engineers select drilling locations and sweet spots.

Elements of Spectroscopy

In shale plays, high-definition gamma ray spectroscopy uses both inelastic scattering and thermal neutron capture to determine elemental weight fractions, mineralogy, and total organic carbon (TOC) for defining reservoir quality in complex lithologies. This data can be used to more accurately estimate hydrocarbon-filled porosity and, ultimately, hydrocarbon in place.

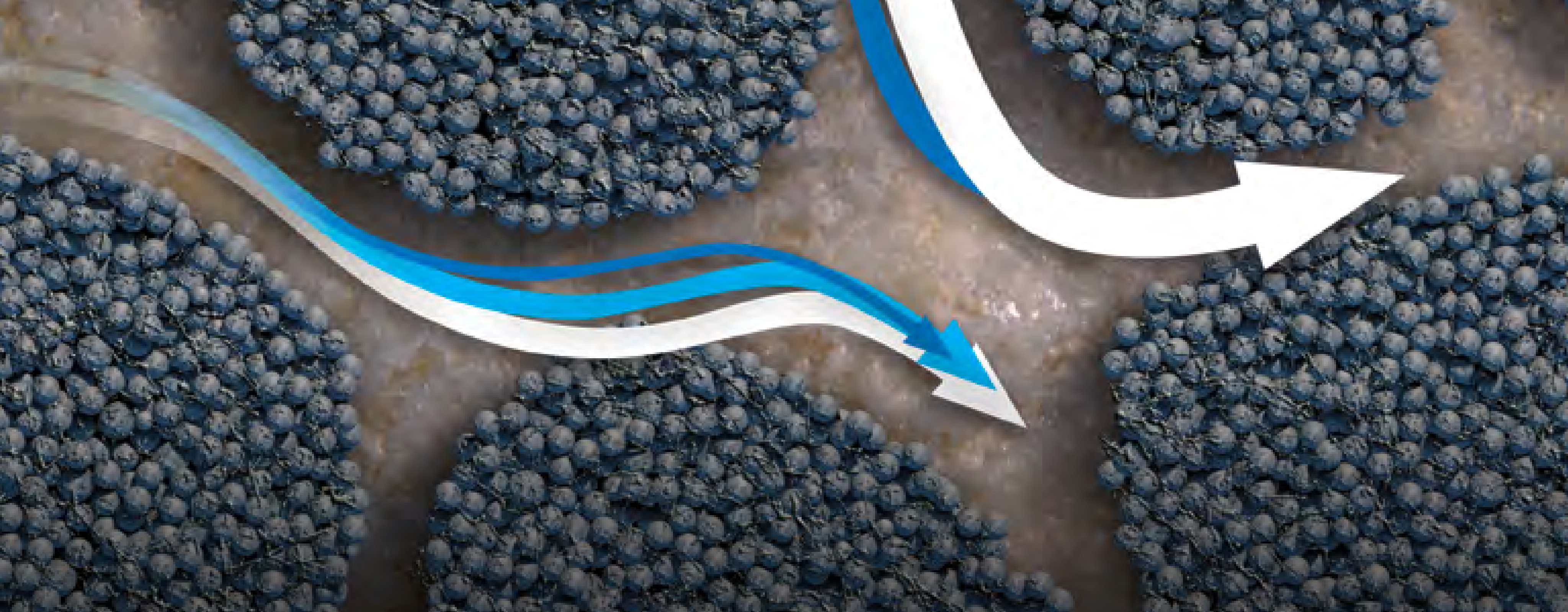
Inelastic Scattering

Inelastic collisions cause a fast neutron to lose a large fraction of its energy.

Thermal neutron capture

After neutron capture, the nucleus is in a highly excited state, emitting characteristic gamma rays.

Induced fracture complexity is a function of fluid rheology, not just geology.

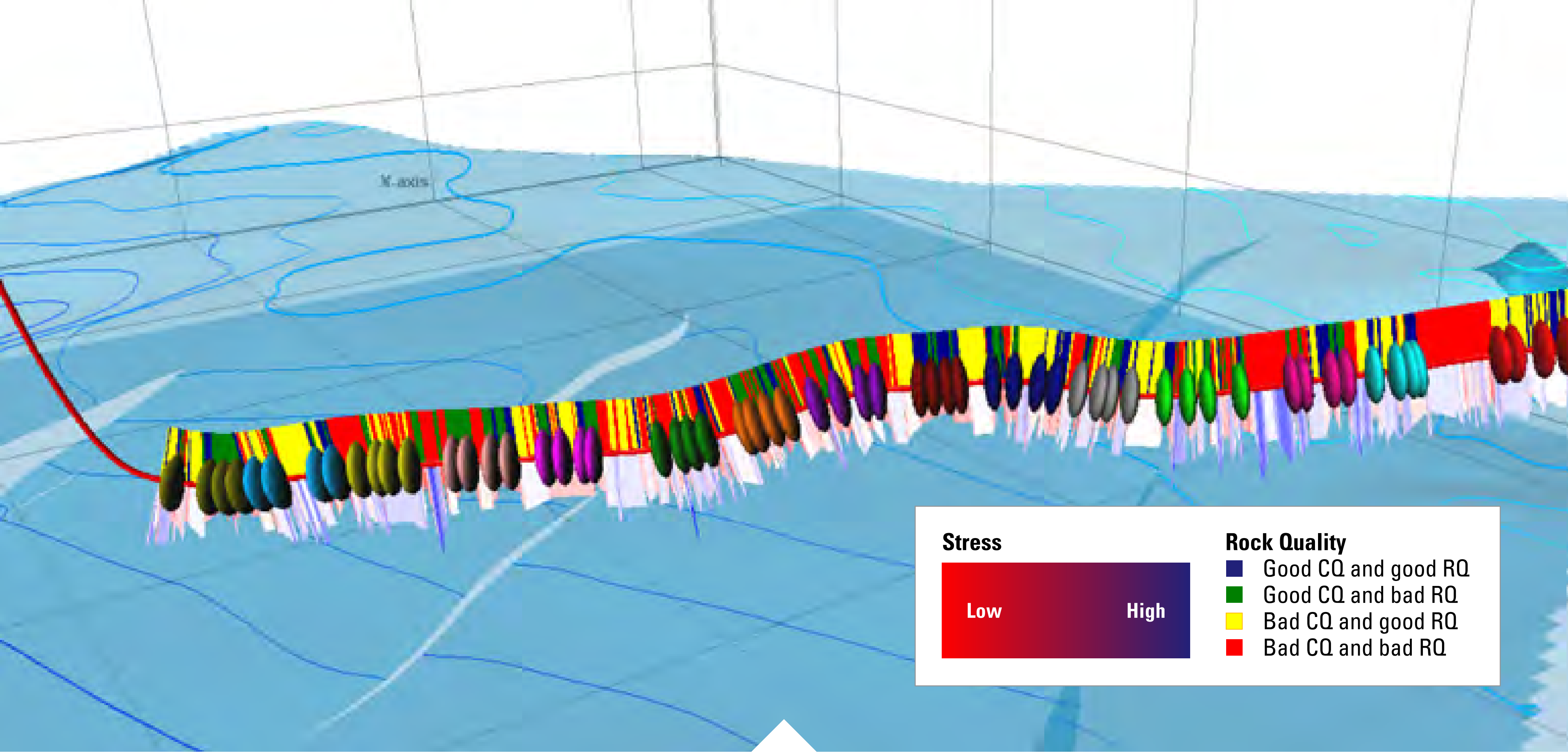


Because of the ultralow permeability range, conductive surface areas in the order of 5 to 10 million ft^2 per well must be created to deliver economic flow rates. However, unconventional reservoirs do not always respond to hydraulic fracturing as planned. Creating a long-lasting conductive surface area depends on pumping the right fluids into the right target.

Fluid Behavior

Rheology, which is the flow of matter, including its elasticity, plasticity, and viscosity, is an extremely important property of fracturing fluids. The rheological properties of both clean and proppant-laden fluids influence fracture geometry and extension during treatment.

In addition to performance and budget criteria, fracturing fluids must meet formation challenges, such as water sensitivity or low pressure. Only the right combination of chemistry and completion quality results in sustainable fracture conductivity and production rates.

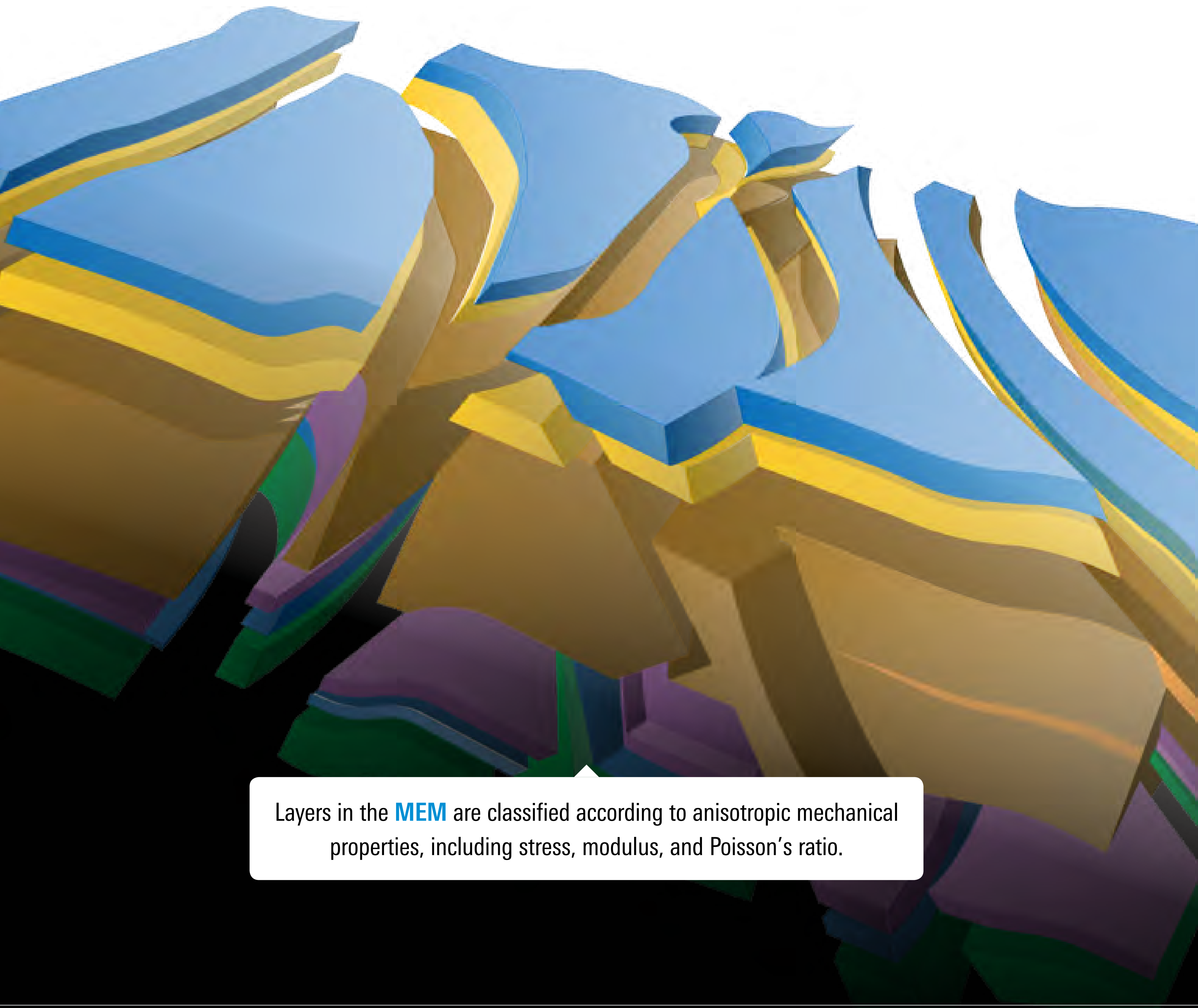


Defining Completion Quality

Formations that are amenable to hydraulic fracturing possess high completion quality. High RQ and CQ are necessary for economic results, yet the definition of sufficient values is always changing. What was considered poor RQ or CQ a decade ago may now be the target in many basins. Academia and the energy industry continually investigate new technologies and techniques to transform what was once considered an uneconomical prospect into a valid asset for development.

An important aspect of the CQ is the degree to which a hydraulic fracture will stay contained within the reservoir target. In cases where significant upper-, lower-, or dual-height growth occurs, job economics can be severely affected. If an engineered fracture treatment stays contained, all the fluid and proppant designed to stimulate the reservoir will be directed toward the target instead of nonproductive zones.

Mechanical earth models (MEMs) help describe the potential for containment. These models take into account the anisotropic mechanical properties common in shales because of their laminations. Laminations impact the in situ stresses and corresponding fracture geometries. MEM simulation runs model the effect of different lateral landing zones, perforation schemes, fracturing fluid types, and staging decisions. Often, several differing landing zones are considered—with final selection based on height-growth criteria.



Layers in the **MEM** are classified according to anisotropic mechanical properties, including stress, modulus, and Poisson's ratio.

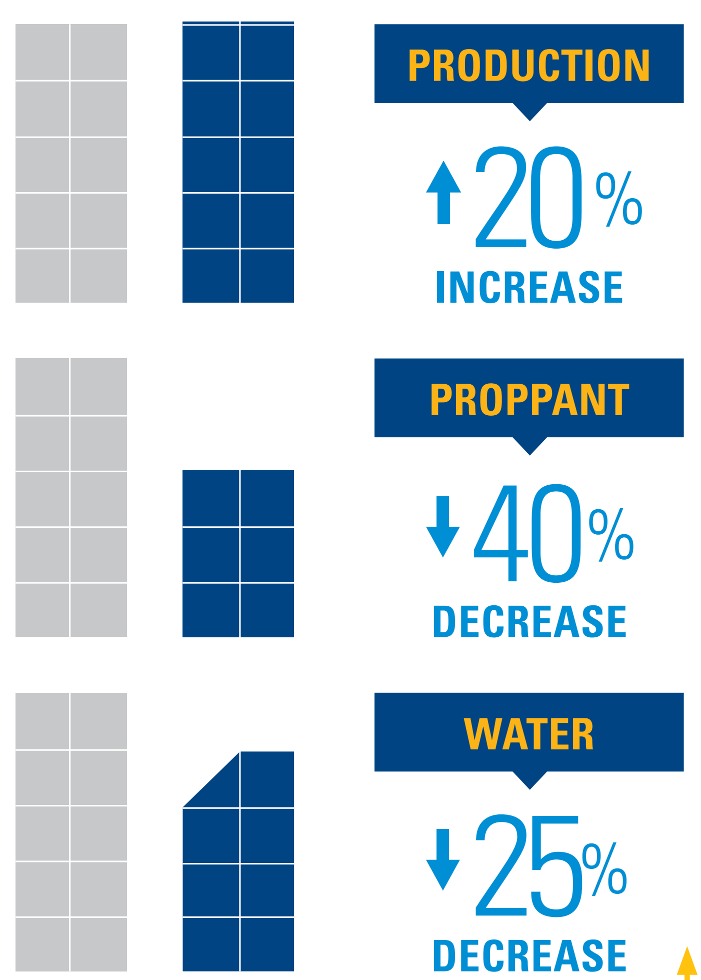
Hydraulic Fracturing of the Future

Flow-channel hydraulic fracturing uses specialized blending equipment and control systems to pump proppant in pulses — creating stable, infinite-conductivity flow channels within the fractures. It helps operators increase fracture conductivity while using less water and proppant. This means smaller operational footprints, simpler logistics, and higher production.

The average HiWAY channel fracturing job **increases production by more than 20%.**

On average, the HiWAY service helps operators **use 40% less proppant per job.**

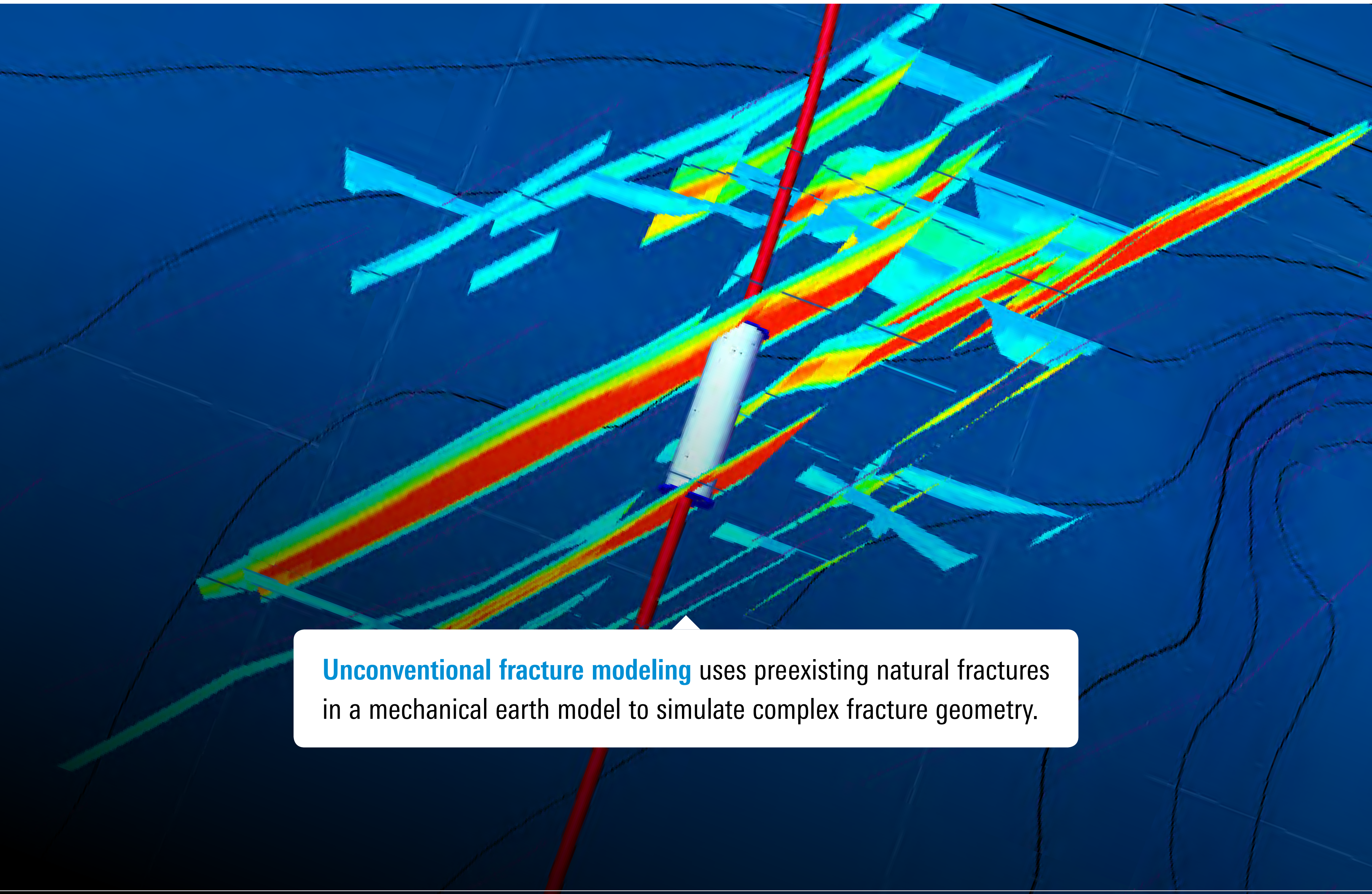
Compared to slickwater treatments, on average, the HiWAY service **uses 25% less water.**



View fullscreen

Modeling Complex Fracture Networks

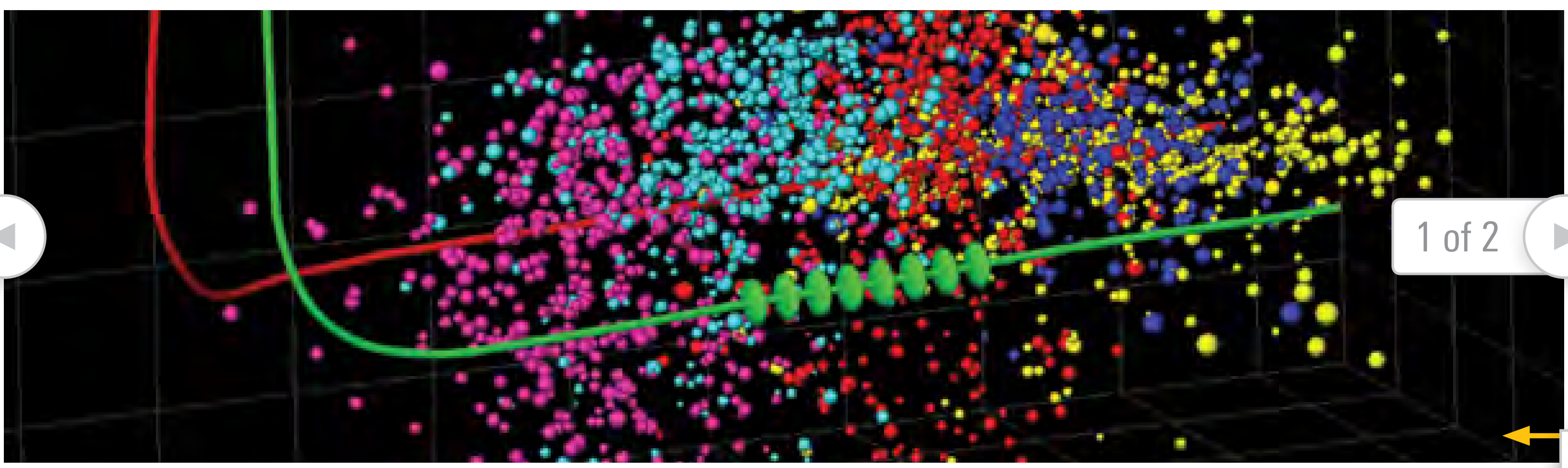
Microseismic measurements characterize hydraulic fracturing complexity in many active organic shale plays. This complexity can be defined as the degree to which created fractures deviate from a classic, bi-wing description of a hydraulic fracture. Determining the CQ must also include complexity. This is done in several ways, but most typically by creating a discrete fracture network (DFN) model to describe natural fractures or fissures in the reservoir. Empirical equations validated through big-block rock laboratory experiments help model the interaction between hydraulic fractures and the DFN. Ultimately, these complex models must be validated via microseismic fracture mapping to ensure that the model represents reality.



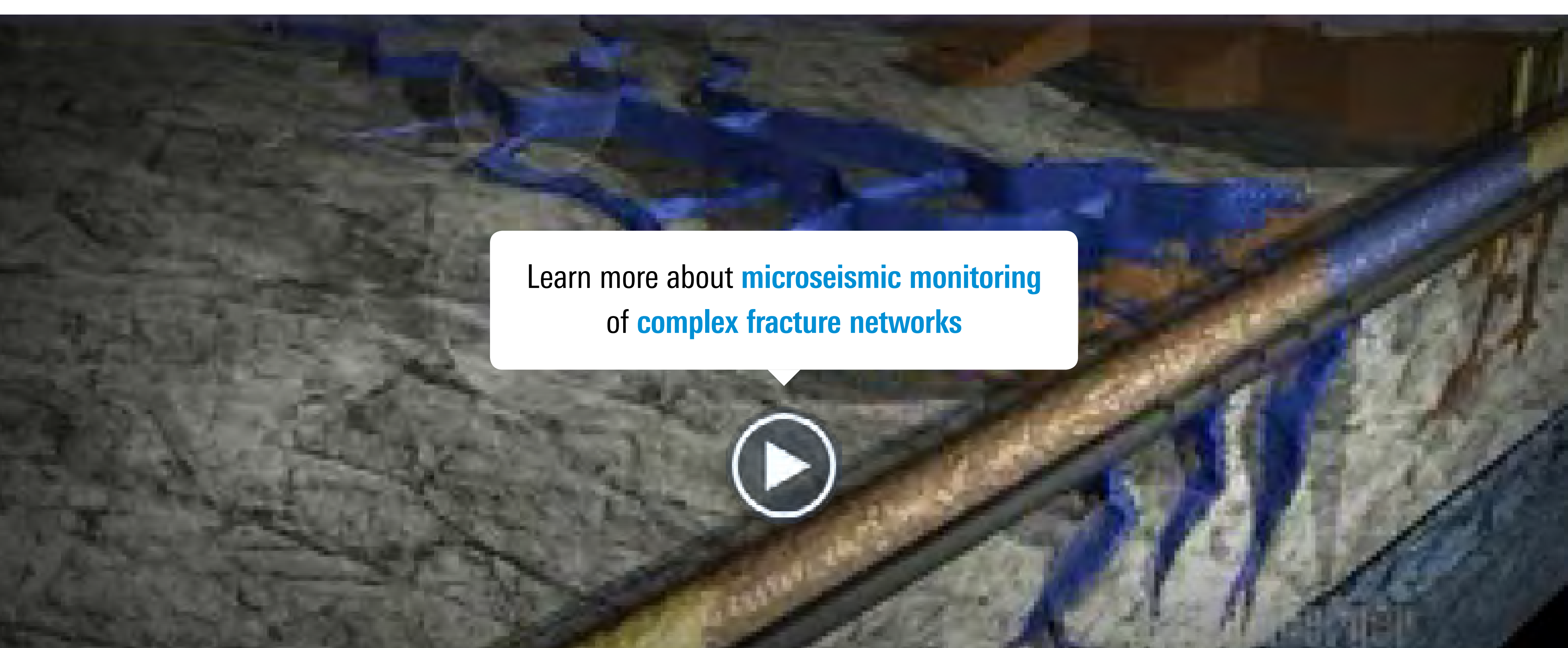
Unconventional fracture modeling uses preexisting natural fractures in a mechanical earth model to simulate complex fracture geometry.

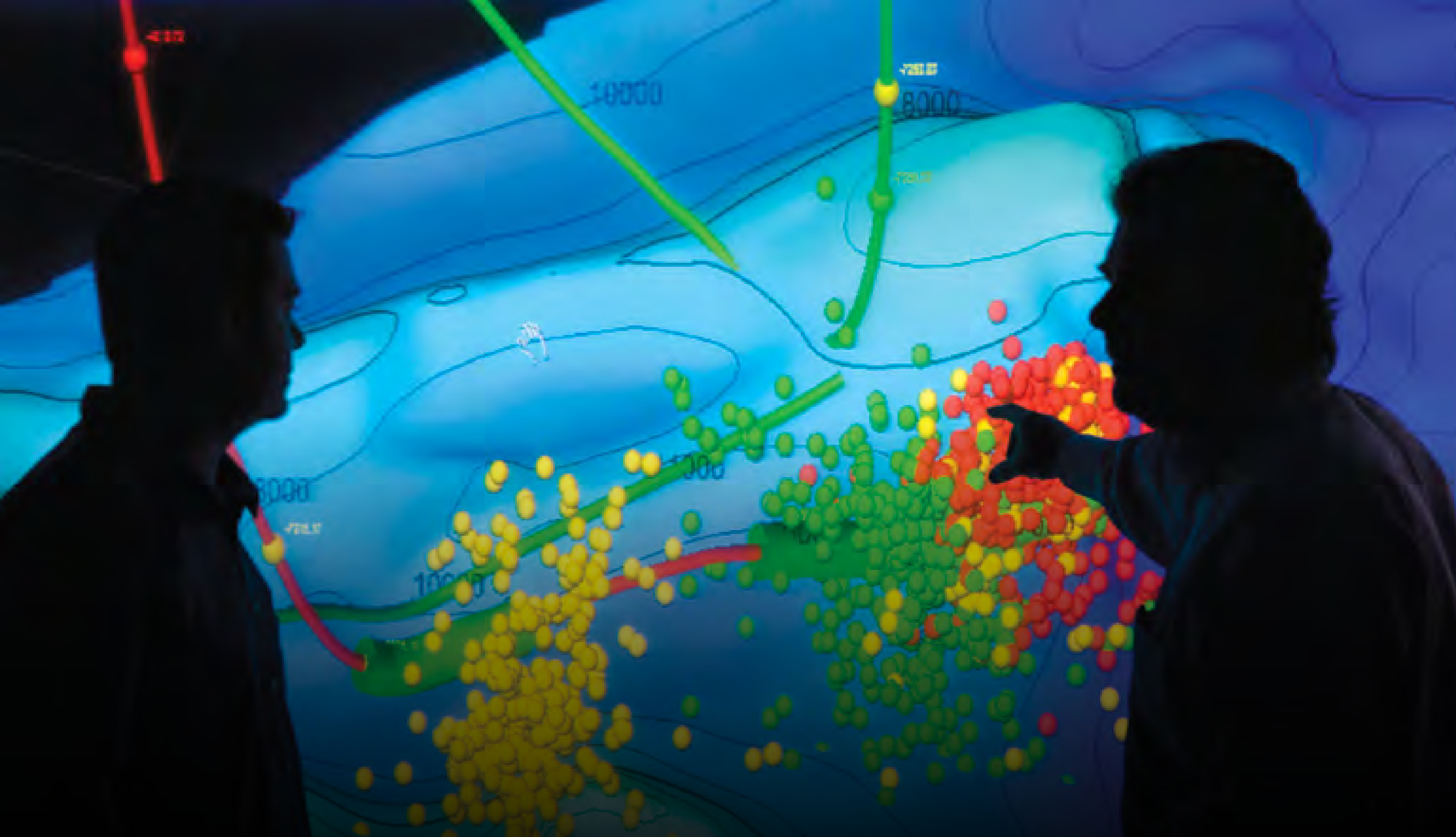
Monitoring Fractures

Whether microseismic events are acquired downhole, at the surface, or with shallow-hole tools, microseismic mapping shows engineers how reservoirs respond to treatment. This data can help operators improve completion designs, change treatments as they are being performed, lower completion costs, and increase productivity. Microseismic data can also be used to calibrate simulations of future treatments—and even help plan the well spacing and layout of entire fields.



In this microseismic monitoring job, five stages were pumped from the treating well (red line) while monitored from a second well (green line). Geophones are indicated by green circles.

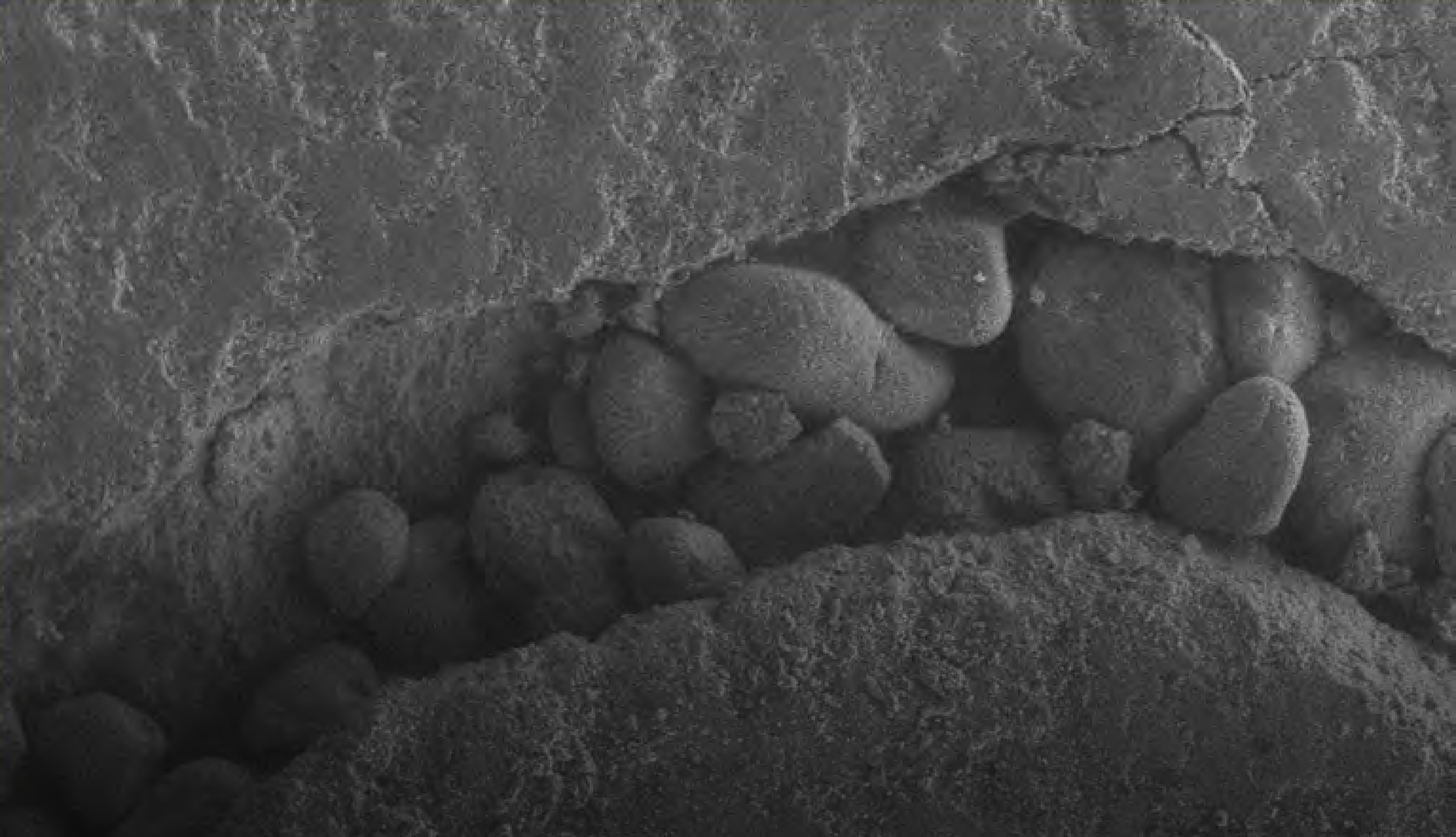




Long-Term Fracture Performance

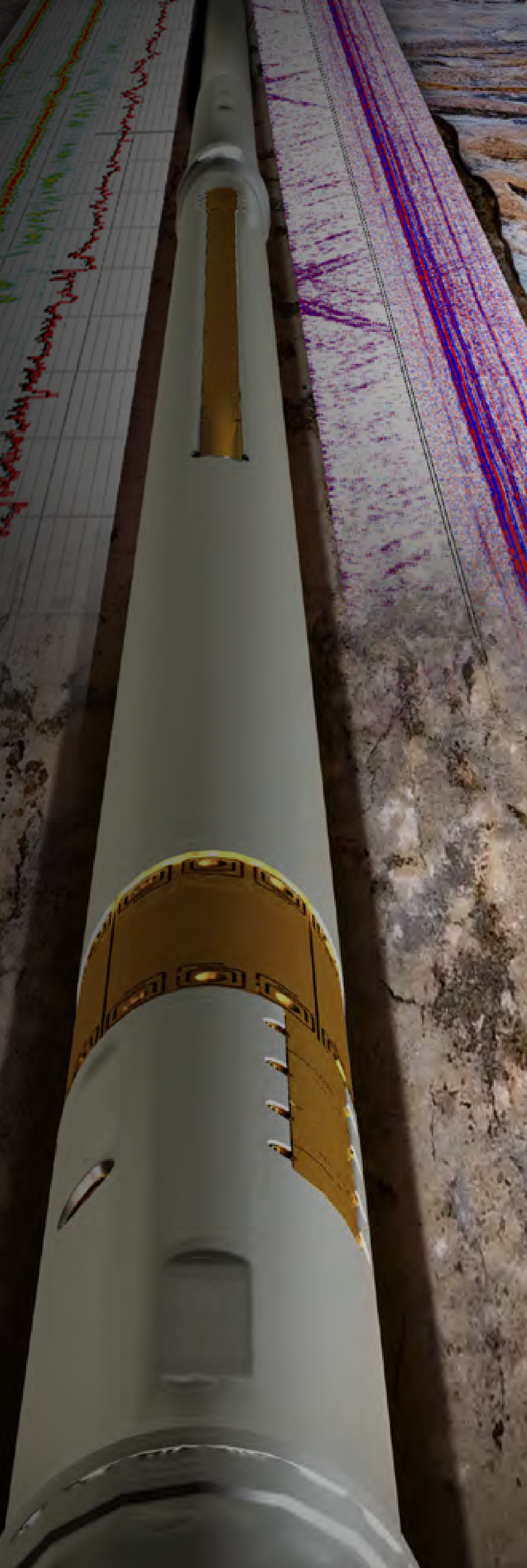
Besides induced hydraulic fracture complexity, there also is the issue of fracture conductivity, which is the percentage of created fracture surface area that will remain conductive and contribute to production. Studies have shown that, in some cases, only 20% of the created fracture surface area contributes to well productivity. Clearly, if all of the created surface area were productive, that would have a huge impact on well performance rates, drainage area, well spacing, and materials usage.

Some possible culprits for the production gap include the potential lack of retention of fracture conductivity and surface area over time, the effect of rock-fluid interactions, and the drawdown controls required to prevent solids production during flow. In addition, a poorly designed perforation scheme or improper fracture port placement along a long lateral can lead to premature screenout or divert proppant and fluid away from the better reservoir sections.



As many as 20% of fracture stages and 40% of perforation clusters do not contribute to production.

When looking at reservoir and completion quality, the entire reservoir and its bounding layers must be considered. Thorough understanding of fracture initiation, propagation, and maintenance in the critical near-wellbore region is paramount—especially in horizontal wells.



Determining the Reservoir Response

Near-wellbore stress, far-field formation stress, fracture width, near-wellbore formation strength, and fracture tortuosity each play a role in determining well performance by influencing fluid and proppant placement during fracturing, as well as the connection between the hydraulic fracture and the well over time. Determining these parameters helps ensure successful fracture placement and desired production response.

When completions are performed using multiple perforation clusters within an individual stage, differences in breakdown pressure and stress often lead to variability in the volumes of treatment that enter each cluster. Determining the near- and far-field stresses and designing the perforation clusters to reach similarly stressed regions balances treatment injection, leading to improved distribution of proppant across the reservoir. Without this information, higher screenout rates and larger variability in production response can be expected.

Understanding Near-Wellbore Stress

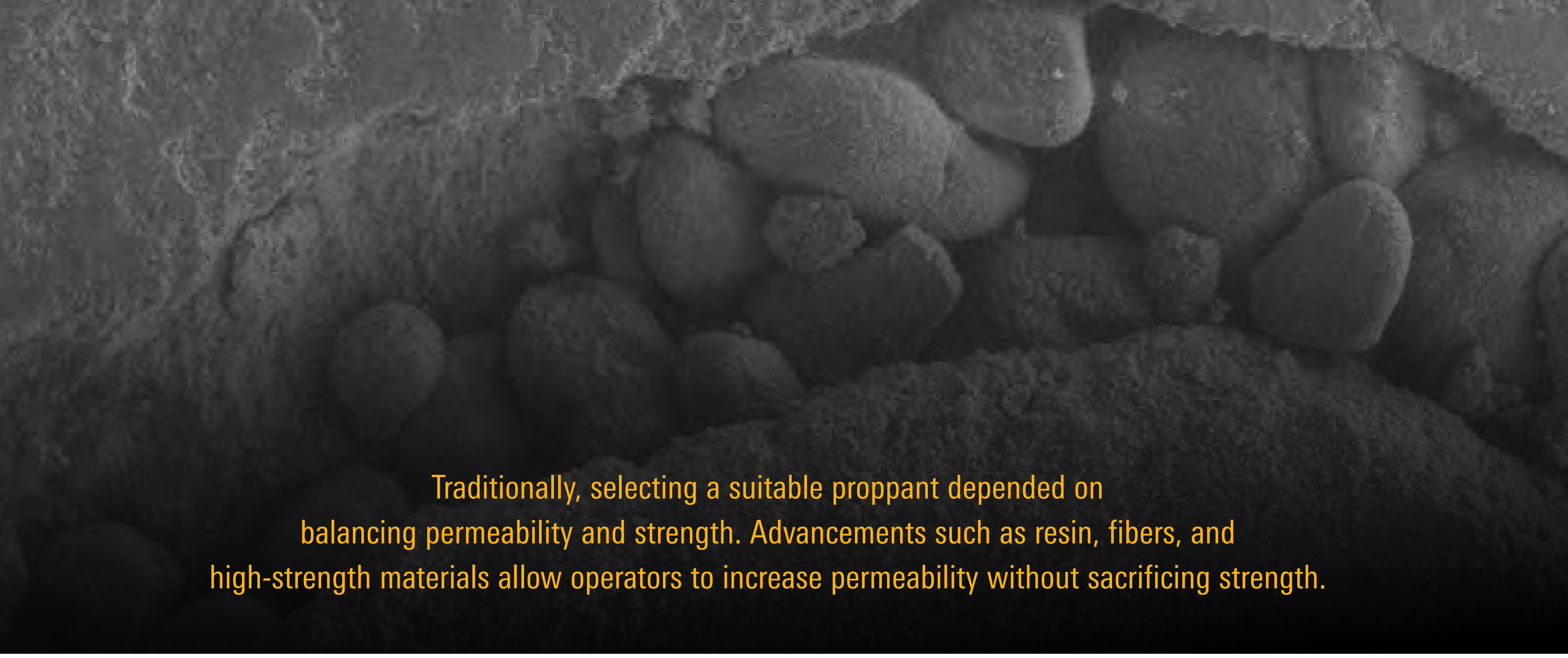
Accurate formation compressional and shear wave data—along with Stoneley wave data—are essential for successful completions, especially in shale. These measurements are used by operators to evaluate fractures in highly deviated and horizontal wells in technologically challenging formations. Based on this knowledge, completion designs can be optimized, increasing future production.

The Impact of Calculations

Fracture width controls proppant placement, including potential premature screenout of individual perforation clusters within a stage. Determined from anisotropic material property equations, as opposed to conventional isotropic ones, predictive modeling of the width helps in deciding where to place hydraulic fracture initiation points along a given horizontal lateral to maximize fracture width and improve wellbore-to-reservoir contact. Often, this calculation can be related to near-wellbore fracture tortuosity effects as determined from pumping tests and related to rock textural features such as laminations, natural fractures, and various other heterogeneous discontinuities.

Because shale reservoirs are usually relatively soft compared with conventional plays, formation failure is a common event. By calculating formation strength and relating it to stress caused by drawdown pressures in the near-wellbore region, a safe operating window can be designed for any value of reservoir pressure.

Accurate measurements and delineation of these properties in the critical near-wellbore region can significantly improve the effectiveness of the hydraulic fracturing process.

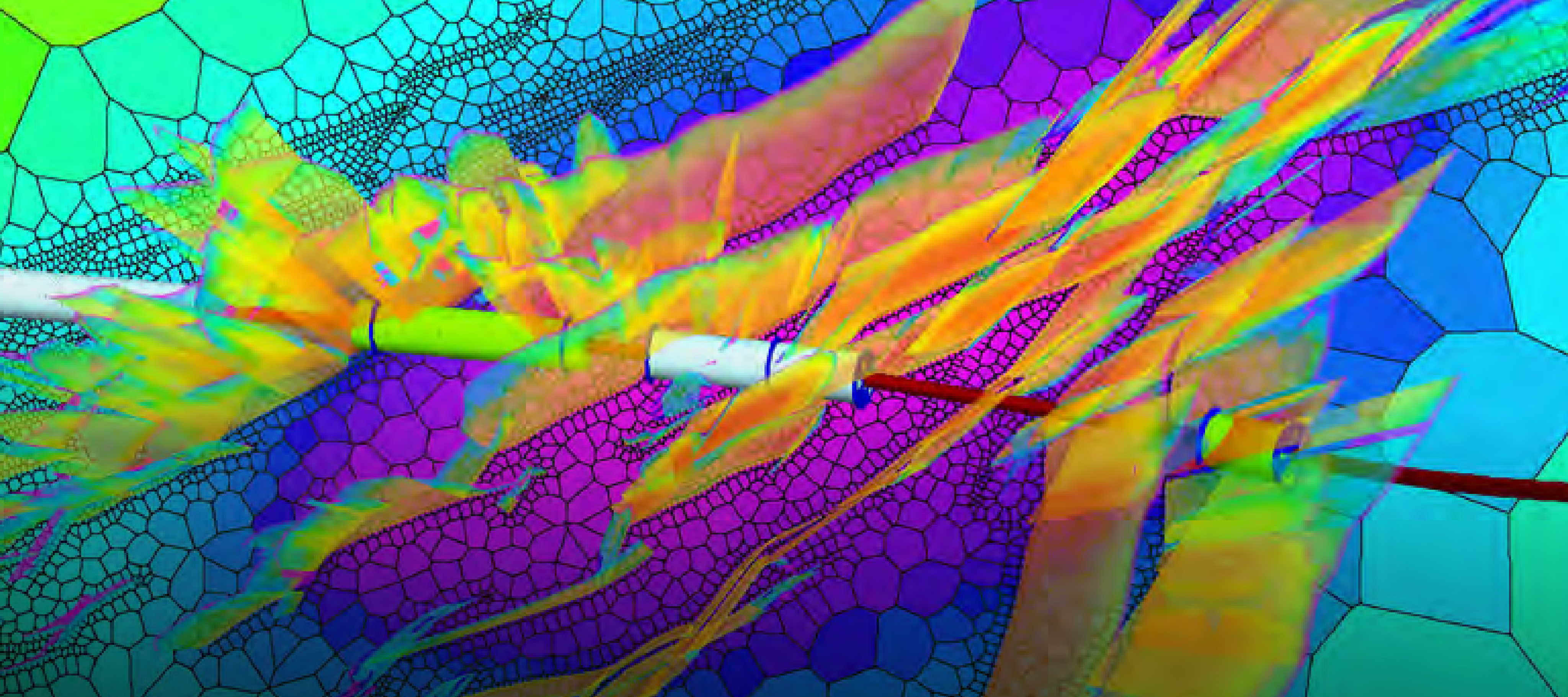


Traditionally, selecting a suitable proppant depended on balancing permeability and strength. Advancements such as resin, fibers, and high-strength materials allow operators to increase permeability without sacrificing strength.

Making Fractures Work Harder, Longer

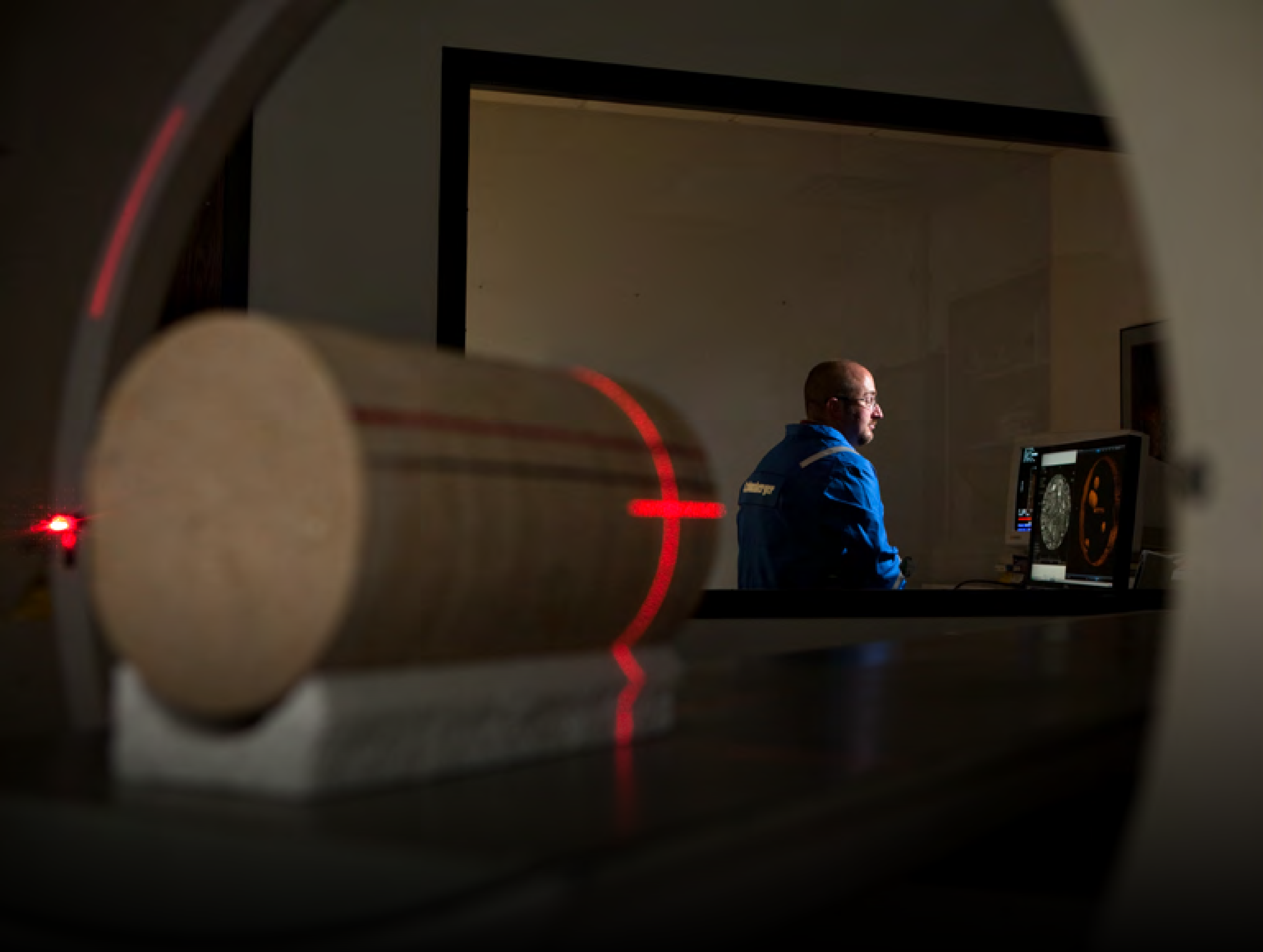
Simulations show that up to 75% of each hydraulic fracture does not contribute to production. Improvements in proppant transport and fluid chemistry can create more conductive fractures, enable higher proppant concentrations, and aid well cleanup, which helps eliminate the need for refracturing treatments later on. Engineered technologies, such as rod-shaped proppant, provide higher proppant pack conductivity in near-wellbore areas while reducing the risk of flowback.

Unconventionally shaped proppant delivers higher long-term fracture conductivity compared with uniform, spherical proppants.



Simulating Shale

Predicting realistic scenarios in complex reservoirs is critical to maximizing ROI. Integrated geological and geophysical, petrophysical, geomechanical, and microseismic data creates accurate reservoir simulations, which can be used to compare different scenarios and engineer better completion designs.



Primary recovery from unconventional resources is less than 10%.

Our understanding of the fundamental properties and dynamic behavior of organic shale reservoirs has come a long way, but many challenges remain. Scientists and engineers are currently investigating non-Darcy flow behavior, porosity types, flow pathways within kerogen deposits, fluid interactions, microseismicity, fractionation of hydrocarbons, natural fracture modeling and more.

A Solution for Softening Effects

As large volumes of water-base stimulation fluids are pumped into unconventional formations, the native equilibrium is disrupted and geochemical reactions between the stimulation fluids and the rock take place. Initial studies have shown a tendency toward a softening of the formation, which can increase proppant embedment effects. As the proppant embeds, the conductivity of the fracture is reduced, adversely affecting production performance. The exact mechanism and means to overcome softening effects, as well as other negative effects such as scaling or salt deposition, are under study.

New Understanding of Fluid Dynamics

Computational fluid dynamics programs determine how the face of the cutting structure was cleaned and cooled, how effectively the hole was cleaned, and how cuttings were evacuated from the bit area and passed up along the annular space. Each color represents the flow path from a specific nozzle. Modeling of fluid flow over the face of the bit (bottom) indicates good total coverage with no dead spots. A side perspective (top) indicates that the flow directed cuttings away from the bit rather than recirculating them around the bit body. The program helps engineers adjust the nozzle count, size, location, and orientation until an optimized design is achieved.

Fluid-Shale Interaction

Gas shale and traditional reactive shale contrast in that their failure mechanisms react differently when coming into contact with fluids. In gas shale, fractures develop between laminations. In reactive shale, exposure to fluids results in swelling and dispersion.

Gas shale

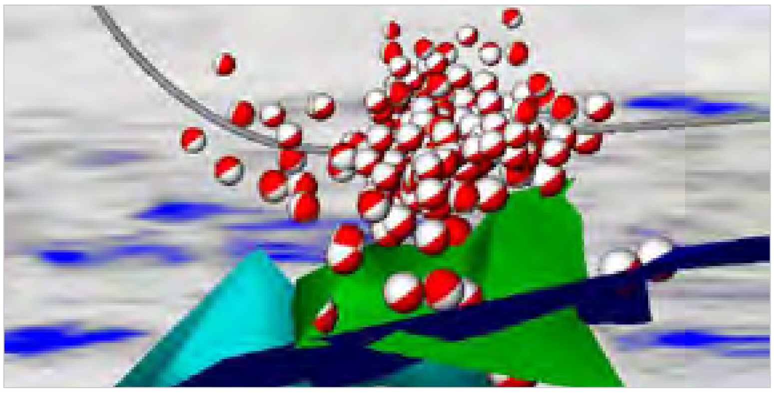
Before fluid contact

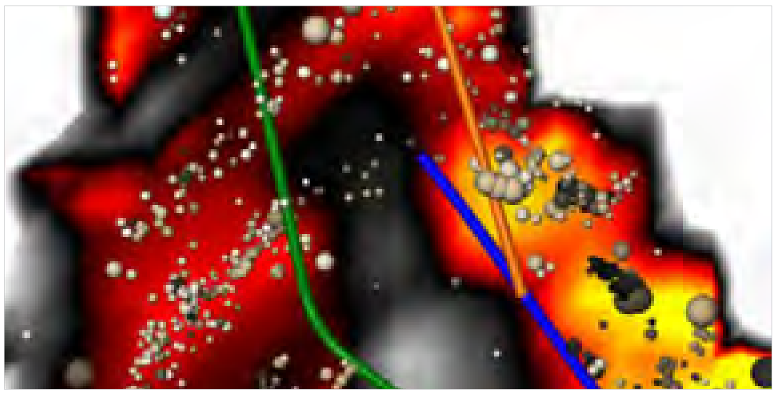
Reactive shale

Before fluid contact

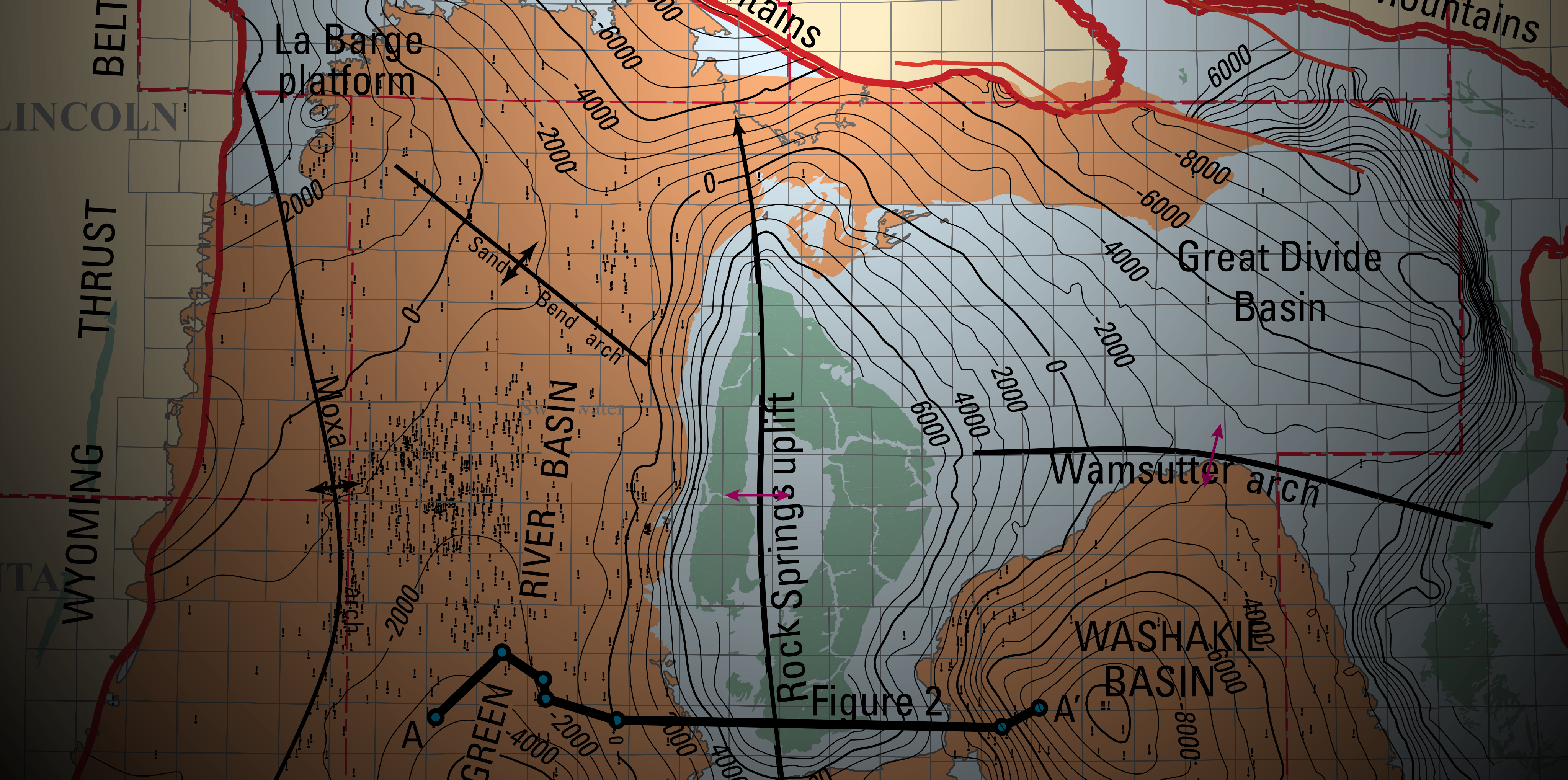
The Meaning of Microseismic Events

While microseismic monitoring of stimulation treatments has led to the development of complex hydraulic fracture models, much is still not well understood about exactly what individual microseismic events mean. Do they indicate areas where stimulation fluid has contacted the rock? Could they be related to offset natural fracture or fissure planes activated by the hydraulic fracturing process? What about proppant placement? Is there a way to determine where proppant has been successfully placed versus where only clean fluid has penetrated?





Advances in the technology of processing microseismic events are illustrated in relation to the rock fabric and fluid property characterization of the reservoir (left) and rock physics models (right).



Revolutionizing Recovery

Further research may also point to the need for additional improved oil recovery (IOR) and enhanced oil recovery (EOR) operations in the future, depending upon the recovery factors that can be achieved during primary depletion. Techniques using carbon dioxide, or other fluids besides water, to flood the fracture system are one promising area of research.

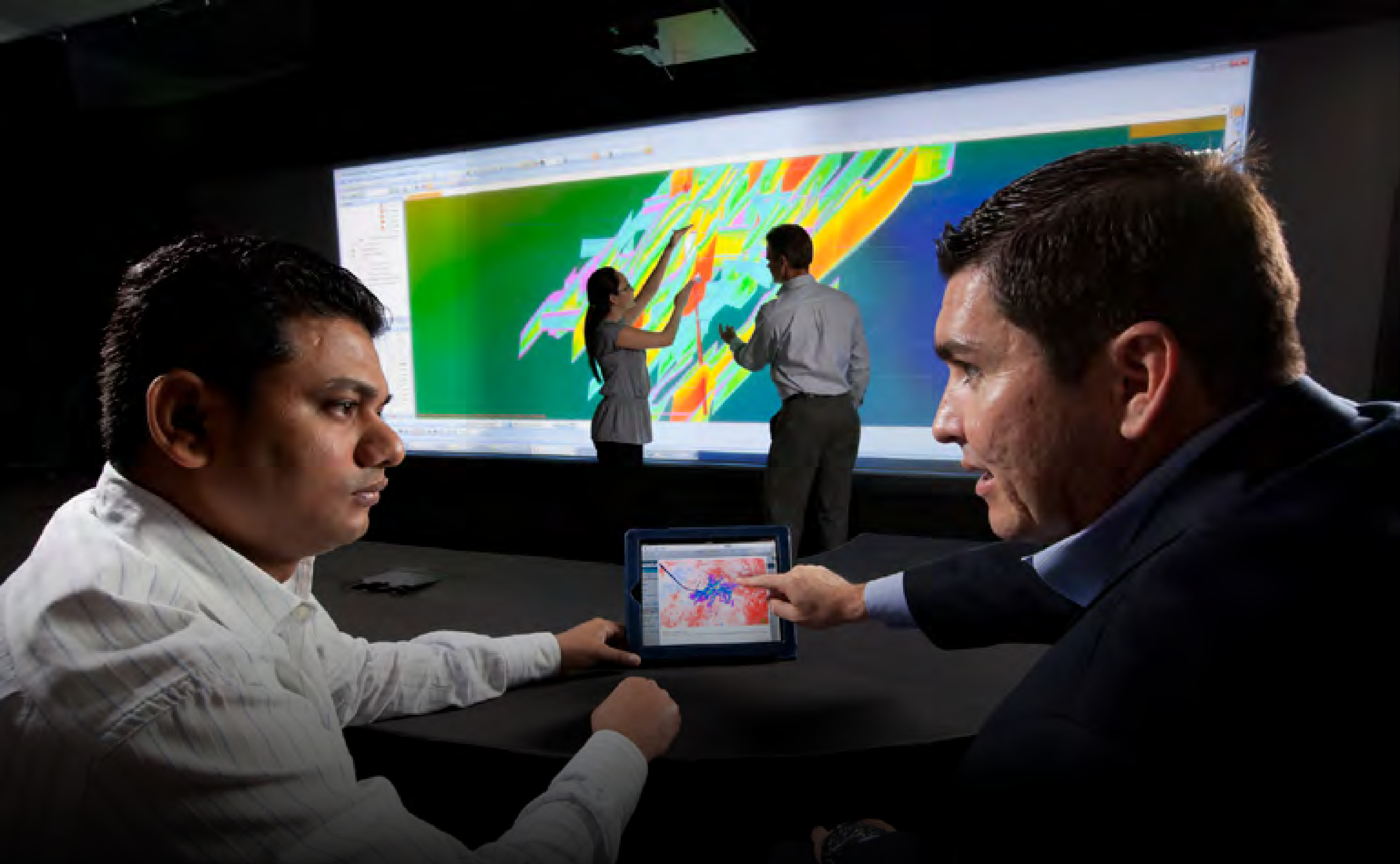
From Kerogen to Crude Oil

The Greater Green River basin spans Wyoming, Colorado, and Utah. With an estimated 3 trillion bbl of oil in place, the basin contains the largest shale oil deposits on Earth. About half of this may be recoverable, which is equal to the entire world's proven oil reserves. However, because the Green River formation is younger in geologic age than conventional oil-bearing formations, its hydrocarbons have not reached thermal maturity. Economic extraction will involve technology to flood or heat the immature kerogen, converting it into a plentiful, viable natural resource.

All highly successful unconventional developments have one thing in common: exceptional integration.

Success in unconventional plays requires a workflow well beyond a trial-and-error approach.

Building a shared earth model from the start improves understanding and decision making, despite many uncertainties. This leads to stronger collaboration and, ultimately, more sustainable results.



Shared Earth Model for Better Knowledge Capture

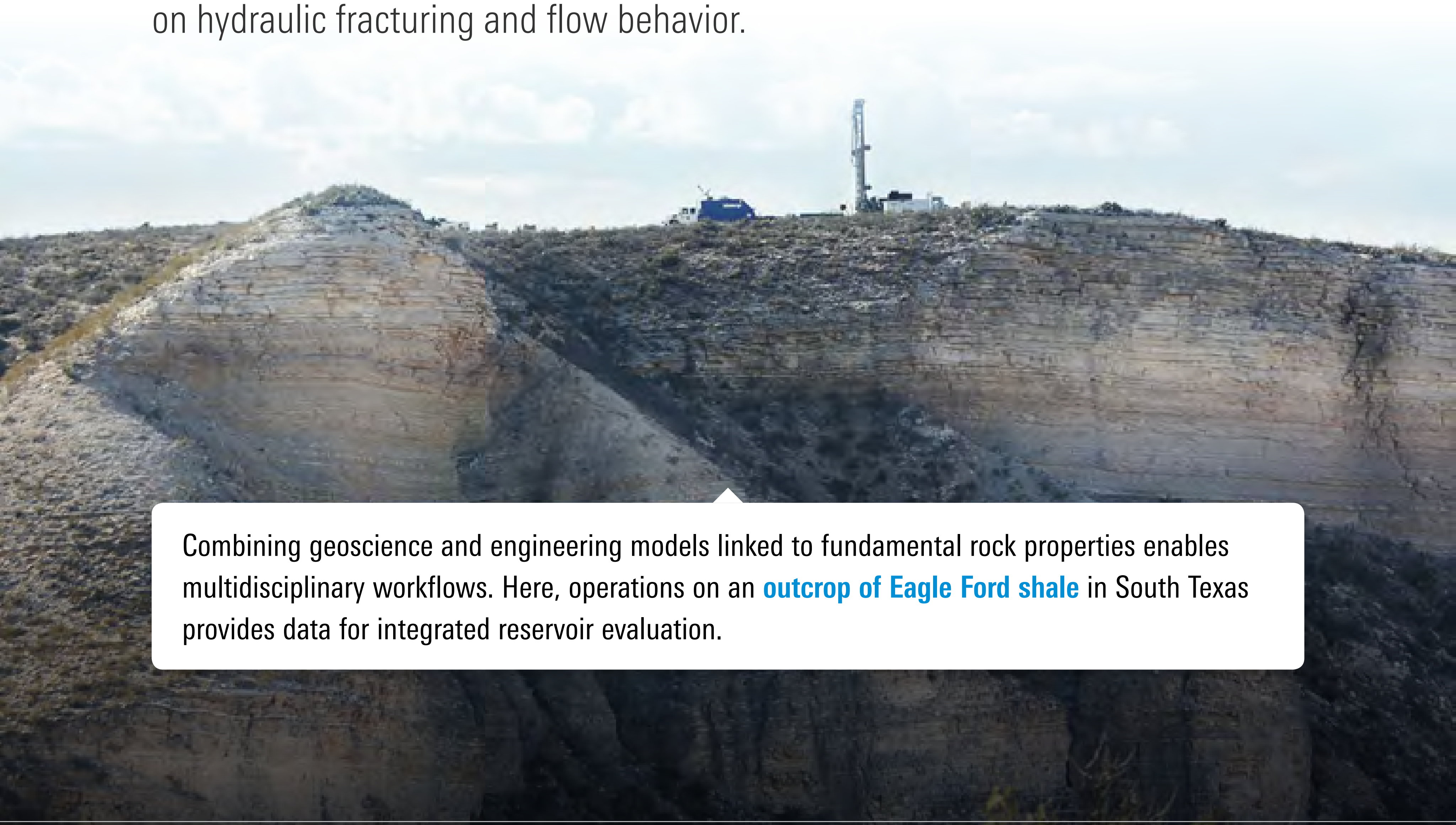
When the earth model is upscaled to simulate well performance, the resulting production forecast helps tie together disciplines involved in the process of optimization. For example, a geologist's understanding of the compressive regimes present in the target field allows the completions engineer to accurately constrain the wellhead, casing design, and completion hardware pressure requirements. In a highly compressive regime, significant tectonic stresses will lead to higher rock stresses and a higher pressure rating for the completion.

When performance forecasts are met as per plan, the model is supported. However, when variances in performance occur, the team reviews the data input and uncertainties in the model to understand the reasons for the discrepancy. The result is a better understanding of the unconventional play and data that can guide future planning.

Stimulation for Data Gathering

During the exploration phase of an unconventional resource play, well stimulation can be considered one more reservoir evaluation technique, along with seismic, core, log, and drilling data sources. Without stimulation that accounts for the science and nature of the rock, the production potential cannot be fully evaluated, because dynamic flow behavior remains unknown in ultralow- permeability rocks prior to hydraulic fracturing. Fracture containment, complexity, treatment pressures, and compatibility between native formation fluids and fracturing fluids are some of the key measurements that should be taken from the stimulation treatment and production testing.

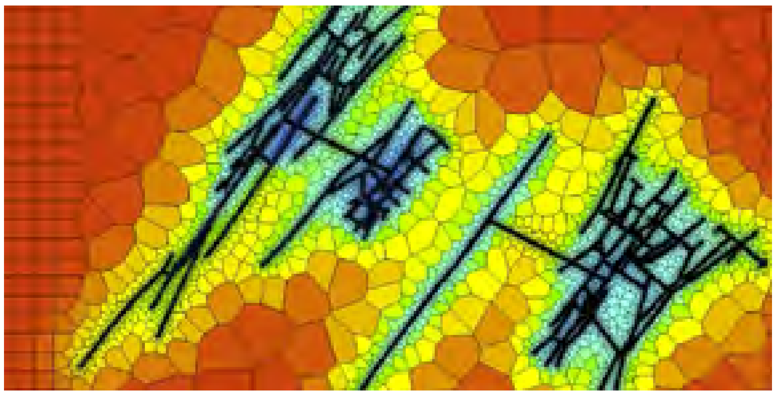
Microseismic measurements are used to compare actual hydraulic fracture dimensions to model predictions. In addition to making simulations more accurate, this calibration process prompts greater integration between geoscience and engineering. Interpretation must also address the affect of natural fracture systems on hydraulic fracturing and flow behavior.



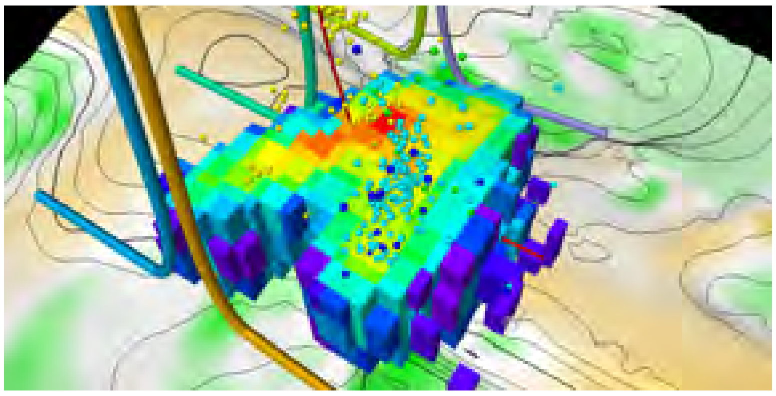
Combining geoscience and engineering models linked to fundamental rock properties enables multidisciplinary workflows. Here, operations on an outcrop of Eagle Ford shale in South Texas provides data for integrated reservoir evaluation.

Improving Production Predictions

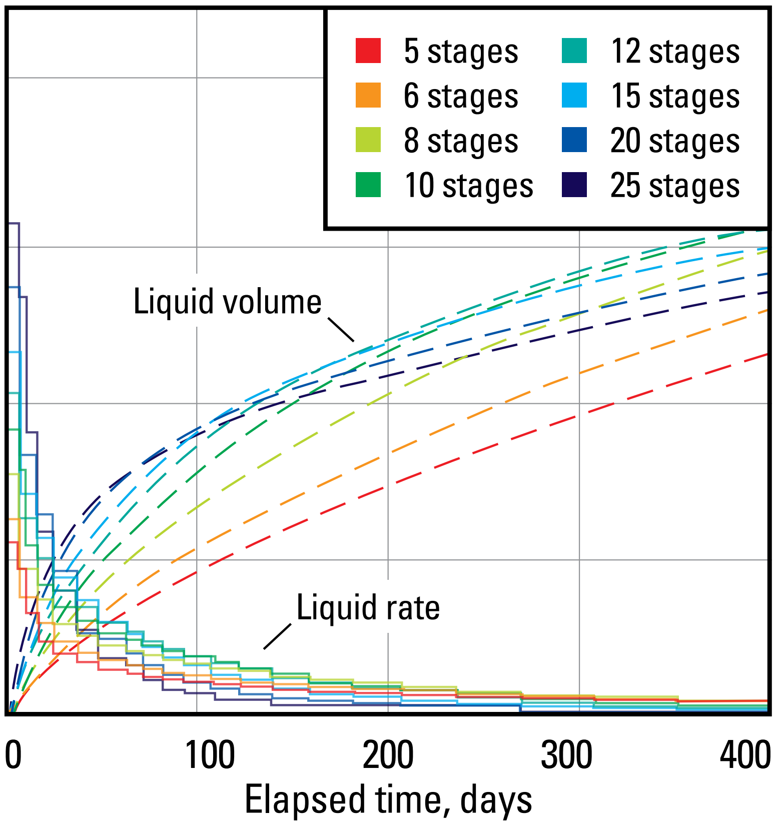
The greatest test of any model is the accurate prediction of production for a given treatment strategy. Once the stimulation is performed, measured pressures are history matched to the model-predicted pressure response. To do this, a representative fracture geometry model is selected, such as pseudo 3D, planar 3D, full 3D, or from the generation of new unconventional fracture geometry models. Microseismic measurements can help decide which model is the most representative and are matched to the treatment to further validate the predicted fracture geometry. Then, via upscaling of the result to a numerical simulator, the expected production performance of the treatment is predicted for various drawdown scenarios. The operational power of this approach lies in the ability to perform what-if scenario predictions to ultimately arrive at an economic maximum result, such as net present value. Only through a highly detailed knowledge of all relevant reservoir factors can this process take place reliably.



Unstructured gridding of complex hydraulic fractures provides a 30-year numerical simulation.



Single-well simulation is part of a multiwell field model.



Multiple completion scenario realizations show expected decline behavior and cumulative production as part of an integrated modeling platform to enable economic optimization of the well completion.

Reservoir Understanding Guides Planning

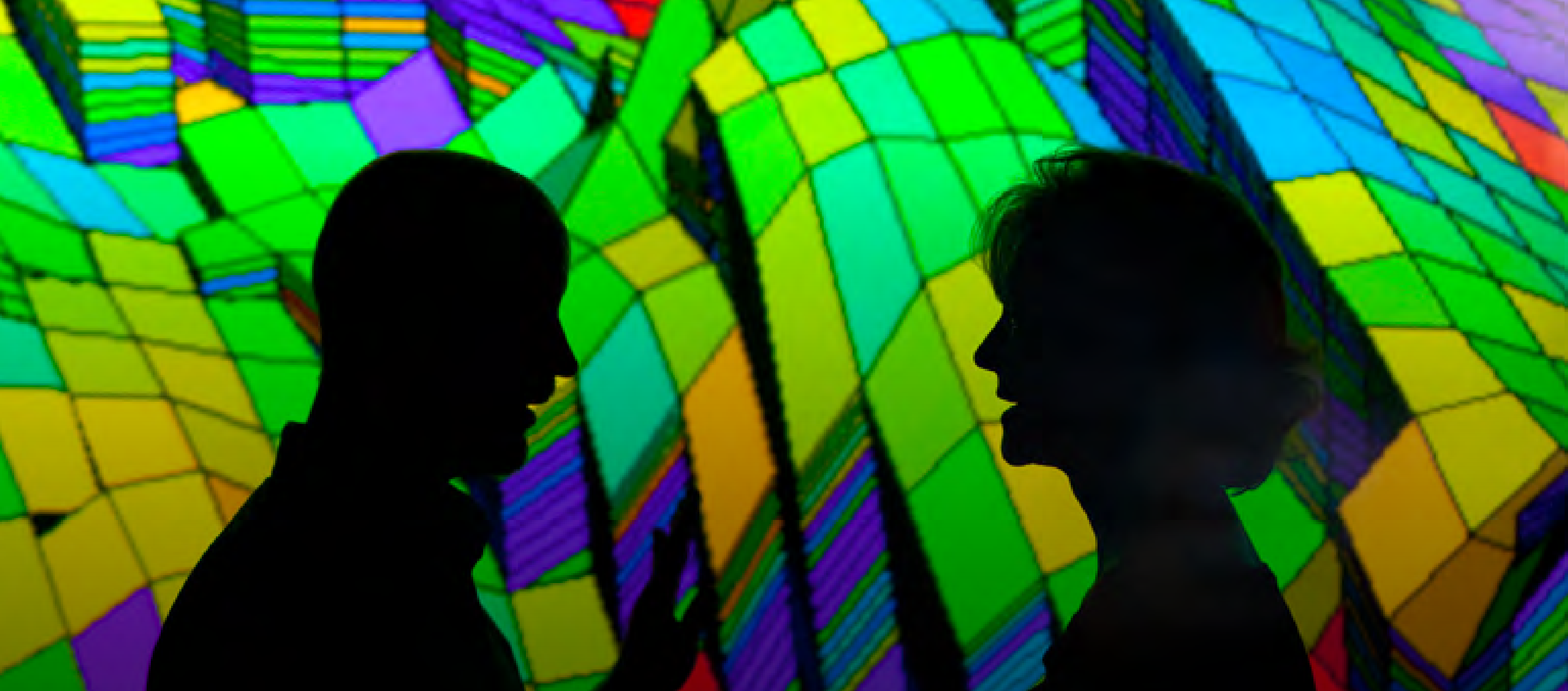
A good understanding of the reservoir across every technical discipline improves field planning and development. Accurate understanding of drilling behavior and completion performance leads to less risk in operational decisions, which should reduce both lost-time and unexpected production shortfalls. For example, applying geomechanical and geochemical information to optimize drilling muds rheology, bottomhole assemblies with azimuthal measurements, and drillbit cutter design can reduce rig time and keep the well path in the best pay zone. Targeted stimulations focused on the productive rock sections instead of out-of-zone or nonproductive zones represent a better use of horsepower and materials. Understanding the unconventional reservoir system delivers the right allocation of technical and operational expertise to support field development.

Exploring Worldwide

Exploratory wells enable proper evaluation and stimulation in shale plays with limited data. First, a pilot well is drilled and cored. Then, logging data and core properties help calibrate the rock petrophysical models. Acoustic logs run from above to below the target zone start the process of building the mechanical earth model. Gamma ray spectroscopy measurements provide understanding of kerogen content and hydrocarbon porosity. The stimulation target zone is selected, and a whipstock is set, allowing the lateral to be drilled. Finally, stimulation zones are selected and hydraulically fractured. Flowback and production testing help determine parameters, such as pressure, reservoir fluid viscosity, and permeability and, ultimately, the economic viability of the play.

Advanced LWD tools improve the speed and accuracy of measurements while eliminating traditional chemical sources.

Formation dynamics testers can be used to determine in situ stress conditions, which are then used to calibrate the acoustics logs.



Through integration and model calibration, unconventional play development is becoming even more efficient — and wells are becoming more productive — every day.

Applying Science to Shale Development

In this new era, development is matched to key understanding of all pertinent aspects of the unconventional play. New wells are drilled in the known location, into a well-characterized landing horizon, and stimulated in selected sections along the lateral. Fracture treatments are sized to provide conductive surface area, which matches reservoir deliverability to the fracture by specifying the schedule of fluid and proppant. Well pad locations and spacing are optimized to project constraints.

As seen in many statistical analyses of production performance, efficiency alone does not lead to the best results. Only the combination of efficiency and science yields hydrocarbons that are cleaner, more cost-effective, and more plentiful than ever before.