Reducing Uncertainty with Fault-Seal Analysis

Oil and gas reservoirs in faulted siliciclastic formations are difficult to exploit. By integrating seismic data, detailed core information, and wellbore and production data, geoscientists can now model fault behavior and incorporate the results into reservoir fluid-flow simulators. This integrated process improves prediction of fault behavior, and reduces the uncertainty and risk associated with complex traps.

A fault can be a transmitter of or barrier to fluid flow and pressure communication. Categorizing fault behavior within these extremes is important for hydrocarbon drilling, exploration and development. Modern fault-seal analysis methods utilize seismic data, structural and microstructural information from high-resolution core analysis, and wellbore and production data to predict fault behavior and to reduce uncertainty and risk in faulted siliciclastic reservoir exploitation.

Sealing faults may be a primary control on the trap in many hydrocarbon reservoirs, but they may also transform a relatively large and continuous hydrocarbon reservoir into compartments that then behave as a collection of smaller reservoirs. Each compartment may have its own pressure and fluid characteristics, hampering efficient and effective field development and subsequent hydrocarbon recovery.

Faults that do not form a seal may prevent oil and gas from accumulating as hydrocarbons form and migrate through structures in the subsurface. Open and permeable faults within an established reservoir may also cause serious lost-circulation problems during drilling operations. The loss of drilling mud can be expensive and dangerous, and can result in the abandonment of wells. Whether detrimental or beneficial, faults and their behavior need to be understood by geologists and engineers to successfully explore and extract hydrocarbon reserves.

Recent developments in fault-seal prediction have focused on two separate but interrelated aspects of faulting: fault architecture and fault-rock properties. The fault architecture refers to the fault shape, size, orientation and interconnectivity. It also refers to the distribution of the overall fault displacement into multiple subfaults. Horizontal fault length may range from millimeters, in the case of microfaults, to hundreds of kilometers. For example, the San Andreas fault in California, USA, is more than 800 miles [1,290 km] long. Detailed studies in outcrops and in the subsurface have shown that longer faults usually comprise interconnected shorter faults. The fault clusters form a fault-damage zone or an interconnected halo of faults at a range of scales that may have a large cumulative impact on reservoir behavior. The displacement of the major and minor fault segments within the reservoir juxtaposes the reservoir across the fault against dissimilar lithologies, which may impact the fluid flow.

The rock properties that develop within the fault zones affect a fault's ability to seal. These properties are affected by the local facies, reservoir-fluid types and saturations, pressure differentials across faults, fault-zone architectures, burial and fault histories, and juxtaposition of the lithologies across faults.1 In addition, pressure and phase changes during reservoir development compound the complexity of analyzing fault-seal behavior.2
Modern methods in fault-seal analysis improve the prediction of fault behavior in the subsurface and reduce the uncertainty in exploiting faulted siliciclastic reservoirs. This article summarizes methods of fault-seal prediction and the associated uncertainties. A brief introduction to basic fault theory helps define the fundamental causes, types and characteristics of faults before presenting a more detailed characterization of the process of fault-seal behavior and prediction. Also discussed are oilfield technologies that are used to measure and predict fault characteristics. Case studies from Hibernia, Newfoundland, Canada, and Prudhoe Bay, Alaska, USA, demonstrate how a better understanding of fault sealing improves clastic reservoir simulation and development, thereby reducing uncertainty and risk.

**Basic Fault Mechanics, Architecture and Properties**

When rocks or rock layers are subjected to tectonic stress, they bend, break, or do both. In its simplest form, a fault is a planar break, or failure surface, in rock across which there is observable displacement, or slip. Contraction...
and extension induce shear failure in rocks. The direction of the principal stresses dictates the orientation of the failure plane, or fault. The strength of the rock controls the magnitude of the shear stress necessary to break the rock.

Although oversimplified, the Andersonian theory of faulting, developed by geologist E.M. Anderson in 1951, is still widely used as a basis to describe the fundamentals of fault orientation in failure. Anderson described the three basic fault types—normal, reverse and wrench, or strike-slip—relative to the maximum regional stress orientations. This theory assumes that one of the principal stresses—\( \sigma_1, \sigma_2 \) or \( \sigma_3 \)—in order from greatest to least magnitude—or the lithostatic load, is always vertical, and that the others are orthogonal and horizontal. The theory predicts that faults will form as two conjugate planes with the following three relationships between fault orientation and principal stresses:

- Faults form at ± 30° to the \( \sigma_1 \) direction
- Faults form at ± 60° to the \( \sigma_3 \) direction
- The line formed by the intersection of conjugate fault planes will be parallel to \( \sigma_2 \).

These relationships are significant because if geologists know the principal stress directions, they can predict fault orientations. If the relative magnitudes of the principal stresses are also known, geologists can predict fault types (above left).

At the seismic map scale, however, faults are rarely planar because of perturbations in the stress field caused by heterogeneities and anisotropy in the rocks. More commonly, faults are composed of separate segments with distinct tips defined by lines of zero displacement. The linkages may occur as hard links where the faults tips connect, or soft links where the fault-tip geometry is influenced by an adjacent fault that lacks a physical connection. The displacement of the stratigraphy across a fault varies in a systematic pattern from zero displacement at the fault tips to a maximum near the fault center. Anomalies in the systematic distribution in throw reflect the complexities in the lithology and adjacent fault segments. Fault complexities preclude a simple interpretation of the fault orientation, geometry and architecture.

A fundamental step in evaluating fault behavior and sealing properties is mapping the faults and constructing fault-plane throw and juxtaposition maps at the seismic scale (left). The limits of seismic resolution, however, introduce uncertainty in the throw mapped across the fault and do not allow the mapping

^ Relating fault types to stress orientation. The Andersonian theory explains the three main fault types relative to the principal stress orientation. These include the normal-fault style, in which \( \sigma_3 \), the largest in-situ stress, is vertical (top); the reverse-fault type, in which \( \sigma_1 \) is horizontal, and \( \sigma_3 \), the smallest in-situ stress, is vertical (middle); and the wrench, or strike-slip, fault type, in which both \( \sigma_1 \) and \( \sigma_3 \) are horizontal (bottom).

^ Interpreting faults from seismic data and modeling using software tools. Complex fault architecture in exploration and development scenarios can be made more understandable with the use of powerful mapping and imaging software such as the Petrel workflow tools application. In this example, color-coded stratigraphic intervals in the hanging wall and footwall are juxtaposed against the modeled fault surfaces in three dimensions.
Faults whose throw is less than the seismic resolution. The total mapped throw across a seismic-scale fault may also include the summed throws of numerous faults that are too small to be detected individually at the seismic scale. The volume of closely spaced fault segments is known as the fault-damage zone.

The mapped throw across a seismic-scale fault displaces the rock layers on a single fault or on a collection of multiple faults, each of which is below the seismic resolution. The offset influences the fault sealing and properties of the fault rocks within the fault zone. A sealing fault may result, for example, if a fault intersecting different lithologies places permeable, reservoir-quality rocks against less permeable rock, such as shale. This is known as a juxtaposition seal. A fault seal may also form if the reservoir is still juxtaposed against itself—where the throw is less than the reservoir thickness—or against another reservoir. This occurs because the rock within the fault zone may develop lower permeability.

Different fault rocks develop under different deformation conditions, and their sealing properties are related to the conditions of deformation and lithologic factors, such as clay content. Faults that cut porous sandstones with low clay content—less than 15%—may develop low-permeability seals from porosity reduction associated with the mechanical crushing of the quartz grains. These are called cataclastic or deformation bands. Disaggregation bands can also develop in clean sandstones, but without the associated reduction in porosity and grain crushing.

Faults in impure sandstones form phyllosilicate-framework fault rocks (PFFR), with higher clay contents—from 15 to 40%—that reduce the porosity and permeability by compacting and mixing the clay particles and quartz grains. Clay smear occurs along faults that cut rocks with greater than 40% clay. The clay layers or shales are dragged and deformed along the fault plane, forming a low-permeability barrier to fluid flow. Cementation may also occur along a fault plane, forming nearly impermeable barriers to flow. These cemented zones, however, are rarely continuous unless they are associated with a regional change, such as an increase in temperature above 90°C [194°F] at which the rate of quartz precipitation increases (above right).

The most common faults found in oil and gas fields are normal faults, and most have some component of oblique movement. Complex, three-dimensional (3D) fault geometries stem from the nucleation, growth and linking of
faults, and give rise to damage zones. An understanding of fault-damage zones is crucial in modeling fault behavior and its impact on reservoir performance.

**Fault-Zone Architecture Characteristics**

An appreciation of fault-damage zone complexity can be obtained through careful study of faults in outcrops. Surface exposures allow geoscientists to observe fault architecture in detail and in a 3D spatial context and scale not afforded by subsurface investigation. Importantly, much of what determines fault-sealing properties occurs at subseismic scales and within the fault-damage zone. Consequently, the study of damage zones in outcrops has become crucial in modeling fault seals and in predicting how they affect subsurface fluid flow.

The damage zone is the volume of deformed rocks around a major fault that has resulted from the initiation, propagation, interaction and buildup of slip along small faults between fault blocks. The deformed volume radiating away from a main fault segment can be divided into inner and outer damage zones. The inner damage zone typically consists of intensely deformed fault rocks that are difficult to map discretely, while the outer zone has a high density of small-throw faults that often maintain an orientation similar to the principal fault segment.

Secondary, subseismic-scale faults, natural fractures and cementation may occur in all three zones. Intensive investigation of fault exposures, like the Moab fault in southeast Utah, USA, has allowed geoscientists to characterize fault-damage zones and make analogies to major faults in the subsurface. The Moab fault has been extensively studied by geoscientists, including scientists from Schlumberger-Doll Research (SDR), Ridgefield, Connecticut, USA, and Rock Deformation Research (RDR) Ltd, Leeds, England.

The damage-zone geometry can also be defined along the strike of a fault, or faults, as three distinct zones (below left). The first zone is called the tip-damage zone and is associated with the stress concentration at the tip of the main fault segment, where the displacement goes to zero. The second zone is called the linking-damage zone, and refers to the volume affected by the interaction between two subparallel, noncoplanar fault segments. The wall-damage zone, the third zone, is located along the fault surface and is a result of damage from continued fault slip or from damage by previously abandoned fault tips as fault propagation continued through time. Secondary, subseismic-scale faults, natural fractures and cementation may occur in all three zones.

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portion of the Paradox basin, the Moab fault is a normal fault approximately 28 miles [45 km] long with a northwest to southeast strike. The fault comprises several linked segments. The longest segment has a throw of 3,150 ft [960 m] to the south, as observed from surface displacement and erosion of Pennsylvanian to Cretaceous sedimentary rocks.

The Moab fault was active from at least the Triassic period until at least the mid-Cretaceous period. The canyon landscape surrounding Moab is ideal for mapping the fault exposure in three dimensions (above). SDR and RDR scientists set out to capture detailed outcrop data along a segment of the Moab fault-damage zone at Bartlett Wash as an analog to similar structures expected but not imaged in the subsurface. Within the study area, the throw along the main fault segment is 690 ft [210 m]. The older, Jurassic-age Slick Rock member of the Entrada sandstone is well exposed on the footwall and exhibits a dense network of small-throw faults within a narrow zone adjacent to the main fault segment.

The geoscientists employed a sophisticated mapping technique, using a high-precision, differential global positioning system (GPS) and rover units to map discrete features to within 0.8 in. [2 cm] (previous page, right). Data coordinates were tagged with key geologic attributes at many stations to capture the complexity and scale of the fault-damage zone. The positions and geometries of major and secondary structural elements, such as faults and natural fractures, were also recorded. Scientists created a digital geologic model to use as an analog for subsurface fault interpretation to facilitate visualization through innovative techniques, such as virtual...
field trips, and to use the fault population distribution as an input to flow models (right).

Although the static geometry and fault-rock properties are the principal controls on cross-fault flow in the subsurface, fault reactivation is another phenomenon that influences the flow properties along the fault. Changes in tectonic stress regimes over geological time, for example, may reactivate a fault, opening pathways that did not exist previously, and allowing hydrocarbons to leak. On a reservoir-production time scale, changes in pore-pressure regimes as a result of current production or injection in and around fault systems can initiate fault reactivation and cause loss of seal.

Local pressure increases near or within the fault plane resulting from injection decrease the effective normal stress, which may cause the fault to reactivate. Also, pressure changes in the rocks surrounding faults, for example from depleting a reservoir, alter the in-situ stresses acting on fault planes and, depending on fault alignment relative to the principal stresses, may lead to reactivation and subsequent seal failure. This behavior has been documented in such areas as the North Sea, the Gulf of Mexico and the Bight basin, Australia.

These pressure changes have major implications in production, enhanced oil recovery (EOR) and pressure maintenance, and in subsurface gas storage, including carbon dioxide [CO₂] storage for the reduction of greenhouse-gas emissions. The reactivation of reservoir-bounding faults compromises fault-sealing mechanisms, shears well casings, and causes compaction and subsidence. The integration of fault-rock strength properties, the fault geometry and in-situ stress conditions provides valuable input for modeling and assessing the reactivation risk. The in-situ stress orientations are interpreted with borehole imaging devices, like the FMI Fullbore Formation MicroImager or OBMI Oil-Base MicroImager tools, and from the acquisition of pore pressure data, using sampling tools such as the MDT Modular Formation Dynamics Tester or the RFT Repeat Formation Tester devices.

**The Roles of Pressure and Timing in Fault Sealing**

An important concept in estimating the sealing capacity of faults relates to the threshold pressure (Pₜ). In water-wet rocks, Pᵣ is the lowest capillary pressure (Pₜ) at which hydrocarbons form a continuous path through the largest interconnected pore throats in the fault rock. Knowing the Pᵣ of different fault rocks, generated under different conditions, allows geoscientists to calculate the maximum petroleum-column height (Hᵣ) or sealing capacity of the fault rock that prevents hydrocarbon migration across the fault. The capillary pressure of hydrocarbons under hydrostatic conditions against a fault seal increases upward from zero at the free-water level (FWL), which is at the base of the hydrocarbon column. A capillary or membrane seal prevents hydrocarbon migration across the fault for a hydrocarbon column height measured from the FWL to where Pᵣ equals Pₜ. Membrane sealing occurs because of the surface tension between water and hydrocarbon, so the effective permeability to hydrocarbon is zero when Pᵣ is less than Pₜ (next page, top).

A hydrocarbon column with Pᵣ greater than Pₜ of the fault rock will migrate slowly across the fault. The flow is retarded by the hydraulic resistant sealing of the fault rock. Hydraulic resistant sealing occurs when the relative permeability to hydrocarbon is low because of the water-wet fault rock and low pressure potential across the fault for small hydrocarbon columns. The hydrocarbons may migrate at a slow rate, but hydraulic resistant sealing provides an effective seal over geological time. At the base of the hydraulic-resistance zone, Pᵣ is equal to Pₜ. Relative permeability to hydrocarbon at this elevation is zero, but increases above this point in a transition zone from membrane sealing up to geologically significant leakage because of an increase in the relative permeability. Geologists consider hydraulic-resistance seal failure significant once the leakage rate exceeds the hydrocarbon-charge rate, at which point hydrocarbons stop accumulating.

Water-pressure differences in the reservoir across a fault or in fault fill influence the height of the resulting hydrocarbon column. Higher water pressure in the aquifer outside the trap, for example, leads to water flow into the reservoir if the hydrocarbon saturation in the fault zone is less than the irreducible water.

**Mapping the Moab fault zone. More than 70,000 structural features were mapped at the Bartlett Wash site to populate an analog model of the fault-damage zone (top). The density of small faults within the damage zone of the main segment of the Moab fault decreases as distance from the main fault increases. Red fault traces are within the inner damage zone, while yellow features are within the outer damage zone (bottom). Powerful software tools allow geologists to use innovative techniques like virtual field trips, capturing the knowledge and experiences of team members at the site.**
saturation, $S_{w,irr}$. These conditions improve the fault-seal potential and increase hydrocarbon-column height. Lower pressures in the aquifer outside the trap and in the fault fill at irreducible water saturation will lead to decreased hydrocarbon-column heights in the trap. These interrelationships between fluids, pressures and rock properties are important controls for predicting fault behavior and sealing capabilities.

Fault architecture, throw distributions, lithologies, fault-rock distributions and properties all impact the flow properties of faults. Fault history, however, is equally important when considering the sealing potential of fault traps in exploration and production. The burial history, deformation timing and hydrocarbon-charge history influence fault-rock properties and their impact on fault-seal capacity.

Successful reservoir-development strategies must incorporate the faulting and burial history to more accurately predict the fault-seal risk. For example, separate tectonic events create new faults and reactivate existing faults. Fractures may propagate, potentially changing the reservoir permeability characteristics. Fault-rock properties also change with burial and uplift. Permeability across faults and in surrounding rocks generally decreases with burial depth (below right). Increases in temperature boost the rate of quartz precipitation, which can significantly reduce the transmissibility across a fault.

Fault-activity maps that color-code the geological timing of structural development help asset teams quantify the risk of developing a prospect or of taking subsequent development steps, such as initiating an EOR process. Knowledge of the geologic history and its impact is also important when predicting fault-sealing properties.

Fault-Seal Analysis Methods
Successful fault-seal analysis methods integrate fundamental information on the fault-zone architecture, fault-rock properties and pressure data. An important tool for evaluating the flow potential across a fault is a strike view, or map of the fault plane with the hanging wall and footwall intersections superimposed on the modeled fault surface.\(^1\) Allan diagrams use this technique to show possible fluid-migration pathways, leak points or sealing areas across the fault, and have also helped explain the location of hydrocarbon/water contacts in various fields worldwide. Allan diagrams typically use the seismically interpreted horizons to define the hanging wall and footwall offset across the fault and lithology interpreted from well logs to identify the stratigraphic changes between the seismic horizons. Sophisticated mapping tools allow the development of Allan diagrams as 3D models. (left) These models require significant amounts of data and can be time-consuming to develop, although new software tools, such as the Petrel workflow tools application, have reduced the processing time significantly.

An alternative to the complicated evaluation of the distribution of the stratigraphy across the fault plane, as used in Allan diagrams, is a simplified juxtaposition triangle diagram, which enables a quick initial examination and prediction of fault-seal capacity. This technique images the hanging wall and juxtapositions for varying throws and allows an evaluation of the juxtaposed stratigraphic intervals for a given throw (below left). These diagrams simplify the analysis of juxtaposition for a single fault plane. The effects of multiple small-throw faults may also be quickly evaluated using these diagrams. The juxtaposition is simply evaluated at the smaller throws for each fault.

In the initial analysis, triangle diagrams show the juxtaposition of the stratigraphy across the fault. Reservoirs juxtaposed against low-permeability rocks such as shales are expected to seal, whereas reservoir-to-reservoir juxtapositions across the fault are more likely to leak. Juxtaposition diagrams may also be used to evaluate the fault rocks present and their associated properties that develop within the fault zone. For instance, the distribution of clay smears from clay-rich layers in the fault zone can be determined and their effects on the seal quantified. Also, critical throws can be assessed when higher permeability cataclastic faults may represent a crossfault flow risk. This occurs where two permeable siliciclastic reservoirs are juxtaposed across the fault—one in the hanging wall (HW) and one in the footwall (FW) (next page).

Several methods have been developed to estimate the distribution of fault rocks within a fault zone. Two of the most commonly applied methods are shale-gouge ratio (SGR) and clay smear.\(^2\) Researchers at RDR have also recently introduced a modified SGR, or effective shale-gouge ratio (ESGR), that permits a greater control on the architecture and distribution of the fault rocks along the fault surface during the analysis.

The SGR method estimates the percentage of clay from the host lithology mixed within the fault zone. The algorithm calculates the net clay within the lithology that is displaced past each
point in the fault by taking the sum of the layer thickness times the clay percentage divided by the fault throw. This calculation is derived across a modeled fault surface with a calculated throw distribution and clay-percentage estimates from well logs. The ESGR uses a weighted SGR that allows a nonuniform distribution of the clays within the section dragged past each point on the fault surface to model a more complex fault-zone process.

Outcrop studies of fault zones have also revealed that clay smearing is a common fault-zone process in which clay is smeared along the fault zone from a local shale bed. The thickness of the clay smear along the fault increases with the thickness of the source shale bed and decreases with distance from the source shale. Multiple shale layers tend to combine to produce a continuous smear, enhancing fault sealing.

The basic method for modeling the fault-rock distributions involves calculating the throw distribution on a gridded fault surface from the horizon intersections on the fault, infilling the detailed stratigraphy with the estimated thicknesses and clay contents, and contouring the derived fault-seal properties onto the fault surface. Contours of capillary pressure measured along the fault provide a calibration to the sealing capacity for the estimated fault-rock properties. These pressure data are often acquired in open hole using formation-sampling tools, such as the MDT or RFT devices.

While the calculation of fault-seal potential across a fault seems straightforward, it may be an oversimplification. From outcrop and exhumed fault studies, geoscientists find that shale smears are not distributed evenly within fault zones; they may be interrupted, creating multiple gaps, which reduce the sealing effect over geologic time scales. One study of the Calabacillas normal fault in New Mexico, USA,


Yielding et al, reference 2.
found that clay smears tend to be continuous for a distance of two to six times the clay source-bed thickness, but then thin significantly away from the base of the clay source-bed on the footwall. Moreover, smears are frequently breached by small-throw faults. Consequently, smear-estimation and seal-calibration techniques can overestimate fault-seal potential, especially near the base of a clay source-bed.

The contours of capillary pressure and fault-rock property estimates over a fault surface are undercalibrated using the methods described. A more accurate analysis should include the calibration of fault-rock properties estimated from core measurements. Measured threshold pressure and permeability across small faults in core help predict the sealing capacity and flow properties of the estimated fault-rock distribution. Fault rocks in core also define the range of fault-rock types, created by processes such as cataclasis or grain crushing, and allow evaluation of the impact of the geologic history and fault timing.

Fault-rock databases from specific basins are key to the calibration of the fault-rock sealing potential. Fault-rock data are a crucial input to successful reservoir simulations, which also rely on field data, including seismic surveys, well logs, core logs and studies, and field pressure-data. These data are also important in reducing the risk in an exploration setting, where there may be significantly less data available.

**Increased Knowledge, Reduced Uncertainty**

Faults in core provide not only a calibration to fault-rock properties such as porosity, permeability and threshold pressures, but also fault distribution and density at a scale below that of seismic resolution. Recent advances in seismic interpretation methods, such as automatic fault-picking and attribute-mapping software, help geophysicists interpret large seismic volumes in less time and in greater detail than manual methods. However, much of the fault detail still exists at a scale below the seismic resolution, so detection of these small faults must rely on high-resolution borehole-imaging tools and the detailed study of fullbore cores.

The highly compartmentalized Hibernia field in the Jeanne d’Arc basin offshore Newfoundland, Canada, demonstrates the importance of detailed core examinations. The Hibernia field is situated in a sedimentary basin within the greater Jeanne d’Arc basin that has undergone multiple rifting events associated with the breakup of the supercontinent Pangea and the formation of the Atlantic Ocean from the late Triassic to the early Cretaceous period.

Since first production in 1997, geologists and engineers with the Hibernia Management and Development Company knew that the two main Hibernia reservoirs were compartmentalized by faults. An estimated 30 fault blocks were identified from observed variations in fluid-contact heights and in pressures. As development of the field continued, there were indications that the field might be even more compartmentalized than originally thought. However, the asset team was uncertain about the degree to which the faults were diminishing individual well production and injection performance.

Fullbore cores were taken from the lower reservoir in the hanging-wall section in two wells, the B-16 2 in Block Q and the B-16 4 in Block R, to characterize the deformation and the fault-zone architecture (above). The cores were examined for geologic structures, and samples were collected for analysis of microstructural and petrophysical properties. The fault rocks were classified according to clay content.

Fault rocks with less than 15% clay exhibited both disaggregation bands, which are localized zones of particulate flow with little grain fracturing, and deformation bands with cataclastic seams with variable amounts of grain-size reduction due to mechanical crushing of the grains. Despite the lack of clay, these fault rocks have an average permeability of 0.06 mD, which is almost five orders of magnitude lower than the host-rock permeability. Fault rocks containing an intermediate amount of clay—15 to 40%—are classified as phyllosilicate-framework fault rocks, and they exhibited even lower permeabilities than their low-clay counterparts. The high clay-content rocks, characterized by greater than 40% clay, formed clay smears. These fault rocks typically have permeabilities of less than 0.001 mD, equivalent to the host-rock properties. The analysis of the fault rocks in core showed that the fault-rock types are capable of significantly reducing the permeability across the faults in Hibernia field.

To evaluate the sealing potential of the faults compartmentalizing the reservoir, the fault-rock types and properties are integrated with the fault-rock distribution estimates from the juxtaposition diagrams. These diagrams show that where the fault throw is less than the individual layer thickness and the reservoir is juxtaposed against itself, the sealing properties are dictated by the cataclastic fault-rock properties. Conversely, where the fault throw exceeds the individual layer thickness, juxtaposition sealing of reservoir against nonreservoir rock is the principal seal.

A juxtaposition triangle diagram of the Hibernia formation at Well B-16 2 demonstrates the predicted fault-rock distributions and their interpreted effects on the fluid flow (next page).


This diagram shows that for throws less than 30 m [98 ft], fault rocks are predominantly cataclasites or zones of grain crushing. On the other hand, where throws are greater than 30 m, the lower permeability, clay-rich, phyllosilicate-rich fault rocks are present. These results show that fault rocks in the Hibernia field have the potential to degrade the performance of both production and injection wells.

When combined with production history-matching models, which yield nonunique solutions from many possible geologic scenarios, the fault-seal analysis calibrated to the fault data from core bolstered the interpretation of how faults affect fluid flow in the field. This led to the drilling of the injector well B-16 21, which was positioned to avoid dangerous fault-damage zones. The new injector well improved reservoir sweep and provided additional pressure support for nearby producing wells.

Fault-Seal Analysis Aids Drilling

Open, conductive fault systems may be as challenging as sealing faults in field development, especially where they pose a serious drilling hazard. Since development drilling began in 1970, the highly faulted Prudhoe Bay field, Alaska, USA, has produced more than 10 billion barrels [1.6 billion m³] of oil. Throughout the field’s history, lost-circulation problems have been commonplace and directly related to the number of faults crossed while drilling wells. With substantial remaining recoverable reserves, continued development by BP and ConocoPhillips requires drilling into smaller fault blocks and through more faults. As a result, lost-circulation problems have increased dramatically, even as total drilled footage has decreased in recent years (above).

Problems reached critical levels in 1998, when 66 out of 120 wells and sidetracks experienced lost-circulation problems, costing over US$10 million. Trouble-time costs added 50% to 100% to well costs. In some cases, loss rates exceeded 1,000 bbl/hr [159 m³/hr], raising serious safety concerns and risking the loss of wells. BP and ConocoPhillips, then Arco Alaska, considered several options to address the fault-related lost-circulation problems. The Prudhoe Bay asset team could choose not to drill risky targets, reducing development options and recoverable reserves, or could employ expensive drilling contingencies that may have mitigated the problem, but at the expense of understanding its cause.

The Prudhoe Bay partner companies, along with RDR, decided to investigate the cause of these lost-circulation problems—faults that act as conduits for drilling mud. In Prudhoe Bay field, more than 5,400 faults have been interpreted by seismic surveys. The faults range in strike length from 500 to 15,000 ft [152 to 4,570 m] with throws from 20 to 200 ft [6 to 60 m] (next page, top). First, the existing seismic data were reprocessed to improve the fault interpretation. The mapped faults were then added to a database, which included fault parameters such as orientation and length. Along with geologic data, drilling data for all wells in the field were compiled, including lost-circulation volumes and rates, and the location of losses. Wellbore data and production history-matching were also used to gain a more thorough understanding of fault, fluid and reservoir behavior. Although this analysis helped explain 80% of the lost-circulation problems, it showed that a more detailed exploration of fault-rock properties across the Prudhoe Bay field was warranted.

Analysis of the fault distributions and fault-rock properties from thousands of feet of core from 14 wells provided the necessary calibration to evaluate fault behavior. Open vuggy fractures in the core identified conductive zones that could pose potential drilling hazards. Full-field and local-stress modeling, integrated with the tectonic history, showed a preferential orientation of conductive faults parallel to the maximum in-situ stress direction. An integrated database of fault styles and architecture, fault-rock properties, and lost-circulation data facilitated the study of fault styles and architecture, fault-rock properties, and lost-circulation data.

The database properties calibrated to juxtaposition and fault-rock distributions from clay-content of individual faults helped reduce the risk of drilling development wells in Prudhoe Bay field. Predrill well planning now incorporates the data from the database to avoid hazardous drilling areas (next page, bottom).

In the year following this integrated fault-characterization project, 65 wells and sidetracks were drilled. The number of problematic wells, those losing more than 100 bbl [16 m³] of drilling fluid, dropped from 32 to 16% of the total wells. Lost-circulation zones were anticipated and accounted for, reducing trouble-time and decreasing drilling costs by US$2 to 5 million during that year. Only two wells had significant problems. A more thorough knowledge of faults in Prudhoe Bay field reduced drilling risk, improved well planning and increased asset team confidence in further development. The significant reduction in drilling risk has opened up more drillable targets that were once deemed too risky, while potentially increasing recoverable reserves.

Complex Problem, Simple Answer
Faults and their influences on fluid flow within reservoirs are complex. Technological advancements have improved our ability to measure these influences, both directly and indirectly. Well-testing techniques, production history-matching and the injection of tracers, for example, help assess whether reservoir compartments exist, and if they do, whether they are in communication or are isolated. Wellbore
measurements and sampling tools also are used to evaluate reservoir rocks, fluids and pressures to determine compartmentalization. Recently, engineers have successfully identified fluid compositional variances related to compartmentalization using the Schlumberger MDT device.23

The evaluation, calibration and prediction of the faults that compartmentalize reservoirs require a systematic analysis that should include integrating datasets from properties measured in conventional core, to subsurface well and production data, seismic interpretation and outcrop and subsurface analogs.

Poorly resolved subsurface fault complexities may be incorporated into reservoir fluid-flow simulators using the results from detailed outcrop analog studies. In simulators, the effects of faults are represented as effective transmissibility factors across defined traverses. Fault-related transmissibility depends on the number of faults, the thickness of the associated damage zones and the fault properties, such as fault-rock permeability and pressure thresholds.

Incorporating the fault-rock properties from databases has improved history-matching and fluid-flow modeling across faults.24 These results still contain risk and uncertainty. In fault-seal analysis, there will always be uncertainties relating to the internal architecture of faults, the host-rock properties, the definition of stratigraphic units from seismic surveys, capillary pressure effects and how far to project the model given the limited amount of well data. Fault-rock property databases provide the range and magnitude of the uncertainty that can be incorporated into risk modeling using Monte Carlo techniques, for example.

In fault-seal analysis, the complexity of faults must be captured and modeled, but the answer must be simple enough to be used effectively in reservoir simulations to reduce uncertainty when exploring and developing enigmatic, faulted siliciclastic reservoirs. —MGG


