Single-Well Data Integration

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Today's arsenal of well logging and seismic techniques provides a diversity of data that is difficult to manage, yet increasingly important to interpret as a unified whole. To evaluate today's hard-to-find reserves, data from different disciplines must be integrated and displayed together.

The diversity of well data cluttering the desks of geologists, petrophysicists and geophysicists indicates the difficulty of data integration. For one thing, data are recorded with a vast range of vertical resolutions. A Formation MicroScanner log records a microresistivity image of the borehole with a resolution of 0.25 inch (0.5 centimeter (cm)), at least 100 times finer than petrophysical logs having vertical resolutions of 2 feet or more. Another jump is required to reach the resolution of surface seismic sections, typically 50 feet (15 meters).

A second hindrance lies in the differing character of the various data. Conventional graphics equipment used to display well data has great difficulty merging logs—basically single parameters varying with depth—with a geologist's typed commentary, and with the images provided by surface or well seismics and the new generation of imaging logging tools. Another formatting problem arises because logging data are measured versus depth while seismic data are measured versus two-way time. Conversion between depth and time is simple in theory but complex in practice.

Then there is the human factor. Any interdisciplinary activity must struggle against entrenched opinion. Not all petrophysicists tap geologic data. Many seismic interpreters know little about log interpretation. Increasingly, oil companies are recognizing the need to convince everyone that data integration is worthwhile—that the whole is worth more than the sum of its parts.

Recently, an interdisciplinary team in Schlumberger's New Orleans, Louisiana, USA office went to battle on all these fronts, producing two integrated data displays for single wells. One combines geology and petrophysics, the other merges petrophysics and borehole seismics. Gulf of Mexico exploration managers are coming to appreciate both as succinct graphical summaries of well data and a mechanism for conveying insight across disciplines.

Geologist, petrophysicist and geophysicist worked side by side in developing these displays, yet breaking the communication barrier took time. Their progress depended on more than graphics dexterity. The displays incorporate a mineral-based approach to rock classification, an improved inversion technique to convert vertical seismic profile (VSP) data to formation reflectivities and a better way of converting depth-based data to two-way seismic time.

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In this article, Formation MicroScanner, GeoColumn, GeoView, ELAN (Elemental Log Analysis) and SeisView are marks of Schlumberger.

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Geology and Petrophysics

The display combining geology and petrophysics (previous page) shows on the left the petrophysical log data and interpretation, in the middle Formation MicroScanner images and their sedimentological and structural interpretation, and on the right a rock classification. The two main advantages offered by this GeoView display are: 1) a visual integration of data that can be used by all disciplines and 2) an enhanced correlation of reservoir units within a field.

In this Gulf of Mexico gas producer, a combination of indicators singles out the best prospects. As a first stab, the petrophysical logs indicate which zones are porous and hydrocarbon-bearing. Next, the rock classification highlights the sandstone reservoir units, indicating their quality—coarse or medium grain, and also shows the nonreservoir mudstones. Finally, the Formation MicroScanner interpretation indicates sedimentological and structural features that reflect the depositional environment, each reservoir unit's lateral continuity and potentially the flow characteristics of the reservoir.

The best reservoir sands appear to be the massively bedded coarse-grained arenites with more than 20-percent porosity between X330 and X340 feet and between X350 and X365 feet. However, the wavy bedding in these sands may limit their lateral continuity and productivity. The lower porosity arenites and wackies below X420 feet that are separated from the top zones by a growth fault, indicated at X408 feet, are probably of inferior quality. All of this information comes from the one display, allowing a rapid assessment of reservoir quality. A flowchart shows how the components of the display are constructed (above).

The petrophysical logs and interpretation are the most conventional. A gamma ray curve is displayed in the depth track at the left edge. To the right, rock volume analysis, water saturation and fluid analysis from mineral-based ELAN computations provide a quantitative petrophysical description of the formation.

The ELAN interpretation method fits openhole log measurements to a model of the formation comprising a suite of minerals and a variety of fluids filling the pore space. The minimum logging suite is a "triple combo"—a resistivity log and two porosity logs—providing for the rock volume analysis just an estimate of total clay volume. Adding a natural gamma spectrometry log, which measures the formation's uranium, potassium and thorium, refines the total clay volume estimation and helps distinguish feldspars from clays. And a geochemical log that measures several more elements through neutron spectroscopy permits estimation of the clay's constituent minerals, differentiates between plagioclase and orthoclase feldspar, and identifies calcite and other minerals. In the fluid analysis track are indicated irreducible water—water permanently bound to clay minerals, movable water, moved hydrocarbons and hydrocarbons in place.

The Formation MicroScanner track displays formation images obtained from arrays of electrodes that measure electrical resistivity at the borehole wall. The measurements are processed to yield variable-intensity...
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<td>Soft sediment deformation</td>
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The menu of sedimentological and structural features used in the GeoView display.

![Image](image.png)

Workstation interpretation of Formation MicroScanner images at 1:4 scale. A mouse is used to mark continuous planar features, which appear as sinuoids. Dip appears automatically on the right of the screen. TD: 28/55 indicates a true dip angle of 28° at azimuth 55°. The geologist can note sedimentological and structural features, transferring the information to the GeoView display if the features persist for a significant depth interval.

The images have an intrinsic spatial resolution of about 0.25 inch. They are normally viewed on a workstation at an expanded scale from 1:5 to 1:20 (below, left). Lamination thickness, bedding sequence, fractures, folds and other features are often readily visible. But these scales are one to two orders of magnitude finer than the 1:200 or 1:240 scale used to view petrophysical data. For compatible viewing, the image data must therefore be massively compressed.

In the composite display, lost detail is compensated for by substituting a sedimentological/structural interpretation of the original images. The interpretation is made at the workstation. A geologist scrolls through the log noting sedimentological and structural features, attaching an interpretation icon to the data for particularly significant features (left). These icons, displayed to the right of the images, subdivide into three categories, from left to right: sedimentological features, structural features and directional information. Formation boundaries are displayed across the entire track.

The rock classification on the right part of the display is automatically computed from ELAN output data: mineral volumes, porosity and saturations. The method derives from the Geocolumn interpretation scheme in which each rock type is represented statistically by a range of log responses, called an electrofacies. A drawback to the Geocolumn approach is that most log measurements respond as much to porosity as to mineralogy. Using ELAN mineral volumes factors out the porosity dependence.

The rock classification instituted by the New Orleans team applies to the deltaic environment of the Gulf of Mexico and borrows directly from the sandstone classification of Pettijohn, Potter and Siever. The Pettijohn et al. system was chosen, first, because it is well known to petroleum geologists and, second, because its main classification variable is percentage of fine-grained minerals, a parameter that in the Gulf of Mexico largely determines reservoir quality (next page).

Sandstones are divided into three groups. The arenite group is relatively clean sandstones containing the least amount of fine-grained materials, less than 20 percent of total. The wacke group contains slightly more fine-grained material, between 20 and 50 percent. The mudstone group, not generally considered a reservoir rock unless fractured, contains more than 50 percent fine-
grained material. These groups are further divided according to the proportions of quartz, feldspar and lithic fragments. Lithic fragments are reworked multigranuline aggregates from other rocks.

The interpretation scheme first tests for carbonate minerals: if calcite at a given depth exceeds 50 percent, the rock is termed carbonate rock. If the ELAN processing indicates smaller amounts of calcite, trace calcite or calcitic is attached to the rock term depending on how much is found. The most probable main classification—arenite, wacke or mudstone—and subclassification—quartz, arkose and lithic—are then picked from the data base depending on the relative amounts of fine-grained matrix, quartz, feldspar and other minerals indicated by the ELAN output. The amount of fine-grained material has been empirically equated with twice the clay volume, which is taken as the sum of the ELAN-derived clay and bound water volumes.

In the display, classifications are listed with additional flags indicating if the zone is hydrocarbon-bearing and if porosity is below a cutoff value of 20 percent. To the left of the descriptions, electrofacies are represented by colored patterns ordered on the right by a log of total clay volume.

Combining Borehole Seismic and Wireline Data

Building on the petrophysical and rock classification interpretations of the GeoView display is the Gulf Coast group’s SeisView display that includes acoustic logging data and borehole seismic data (next page and see “Integrating Borehole and Seismic Data,” page 36). This example, from an offshore Louisiana well, shows the gamma ray log and ELAN interpretation on the left and rock classification on the right. Between, from left to right, is a comparison of compression and shear travel times, the green shading between them indicating the possible occurrence of hydrocarbon; logs of formation dip and azimuth derived from dipmeter or Formation MicroScanner logs; acoustic reflection coefficients derived from both logs and a vertical seismic profile (VSP); and the VSP corridor stack.

Data here are plotted versus seismic two-way time in seconds and at a much reduced depth scale—equivalent depth values are shown in smaller type. Just as the Formation MicroScanner log was squashed to fit the scale of conventional openhole logs, so openhole logs must be compressed to fit the coarser scale of borehole seismic data.

The Pettijohn et al. classification of sandstones.

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Resampling log data versus time to fit VSP data requires knowing the seismic two-way time to any well depth. This is determined for a few depths from a check shot or VSP survey and then between these depths from drift-corrected acoustic logging data. The log data are then resampled at regular time intervals. Usually, 1 millisecond [msec] is used, but this can eliminate detail. In a 30-percent porosity sandstone, sound travels 10 feet [3 meters] in 1 msec, and beds thinner than this can disappear. To preserve detail, the Gulf Coast team programmed the sampling to occur every 0.1 msec, keeping resolution to 1 foot [31 cm] (next page, below).

The purpose of combining borehole seismic and logging data is to enhance surface seismic interpretation. In a two-stage process, interpreters first try to correlate petrophysical and geological boundaries on logs to events in the VSP corridor stack. Then, they tie the VSP events to reflectors in the surface seismic section. These links enhance not only the structural interpretation made on a section but also the quantitative interpretation of seismic amplitude data, increasingly used to infer lithology and identity hydrocarbons.

The main tool for making the tie in the first stage is the reflection coefficient, defined for each formation boundary as the ratio of reflected to incident acoustic energy. The SeisView display shows reflection coefficients computed from both VSP and logs—spike traces in the middle track. Reflection coefficient is expressed:

\[ \frac{\rho_2 \nu_1 - \rho_1 \nu_2}{\rho_1 \nu_1 + \rho_2 \nu_2} \]

in which \( \rho \) and \( \nu \) are density and acoustic compressional velocity, and the two subscripts refer to formations above and below the boundary. These data can be obtained directly from logs.

Obtaining reflection coefficients from a VSP is more difficult. Coefficients must be established that reproduce the corridor stack when convolved with a wavelet simulating a pulse of seismic energy. Traditionally, a least-squares best-fit approach is adopted with the two-way time location of boundaries fixed and the value of the reflection coefficients allowed to vary. In a new method called minimum entropy inversion, both the location of the boundaries and the reflection coefficient values can vary. The result is a minimal set of reflectors that best reproduce the corridor stack.

Combining borehole seismsics and petrophysics in a SeisView data display from an offshore Louisiana well. From left: petrophysics, borehole seismic data, rock classification.
It is reassuring when reflection coefficients from logs and VSP correlate, but lack of correlation may also provide the interpreter with valuable insight. VSP surveys respond to average rock properties for hundreds of feet around the wellbore, whereas logs respond to within just a few feet—or inches for an acoustic log. A lack of correlation may indicate a variety of structural phenomena not observable with logs alone.

In the offshore Louisiana example, some of the mismatches may be readily explained; others are ambiguous. The strong, positive VSP reflector—red spike going right—at 2.018 sec correlates well with the oil/water contact apparent in the ELAN display. This boundary is not obvious on the log-derived reflection coefficient log—green spikes—perhaps because the zone is well flushed and the acoustic logging tool simply does not see the change in fluids.

The large feature on the corridor stack at 2.045 sec breaks into two negative events on the VSP-derived reflection coefficient log, at 2.040 and 2.046 sec respectively. The bottom one correlates with a log-derived reflection coefficient and with a shale/gas-bearing sand boundary observable on the ELAN display. The 2.040-sec event correlates with the top of a thin sand above. A glance at the full VSP display, however, shows the single event on the stack spreading to two events away from the well (above, right). Most likely, the thin sand thickens as it goes beyond the reach of well logs. The sudden change in formation dip at 2.040 sec seems to confirm this hypothesis.

Another amplitude feature on the corridor stack, at 2.138 sec, provides a large negative reflection coefficient at 2.136 sec. This does not correlate with the top of the gas-bearing zone at 2.130 sec, indicating that the character of this gas-bearing zone changes as it moves away from the well.

Like the geologist and petrophysicist, the seismic interpreter needs integration to create a more sophisticated and reliable picture of the subsurface. These and similar displays will evolve as experts struggle to juggle increasing amounts of disparate data. —MF

7. Drill refers to differences in acoustic travel time measured during a borehole check shot survey compared with travel times derived from acoustic logging data.

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