

# Nuclear Magnetic Resonance Comes Out of Its Shell

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**Advances in measurement technology, along with improved processing techniques, have created new applications for nuclear magnetic resonance (NMR) logging. A new NMR tool delivers conventional NMR-based information as well as fluid-property characterization. These NMR data identify fluid types, transition zones and production potential in complex environments. Placing this information into multidimensional visualization maps provides log analysts with new insight into in situ fluid properties.**

Petrophysical evaluation involves a lot of science and a bit of art. The scientific basis of a new measurement technique often develops from step changes in technologies. The art of application sometimes plays catch-up while interpretation tools are developed to fully exploit new measurements. Attempts to integrate new forms of data into existing workflows may be met with resistance by those skeptical of the added value of the new information. In addition, the learning curve inherent in adopting new concepts is often steep, which can be at odds with the time demands of busy geologists and petrophysicists.

Nuclear magnetic resonance logging is an example of the physics of measurement—the science—being understood and developed before petrophysical analysis—the art—integrated the measurements into standard workflows. Although NMR was initially introduced in the 1960s, it took 30 years to develop an NMR acquisition tool that could deliver the information that physicists knew was available. The first successfully deployed pulsed-NMR tool was introduced in the early 1990s by the NUMAR Corporation, now a subsidiary of Halliburton. Equipped with

permanent, prepolarizing magnets, these logging tools use radio frequency (RF) pulses to manipulate the magnetic properties of hydrogen nuclei in the reservoir fluids. Schlumberger followed soon after with the CMR combinable magnetic resonance tool.

In general, NMR measurements were not accepted enthusiastically because the data did not always assimilate well with existing interpretation schemes. However, early adopters found applications for the new measurement, and, as tools evolved, petrophysicists established the value of NMR logging to the interpretation community—creating an expanding niche in the oil and gas industry. Today, most service companies offer some form of NMR logging tool, and LWD NMR tools have been developed to provide reservoir-quality information in real time or almost real time.

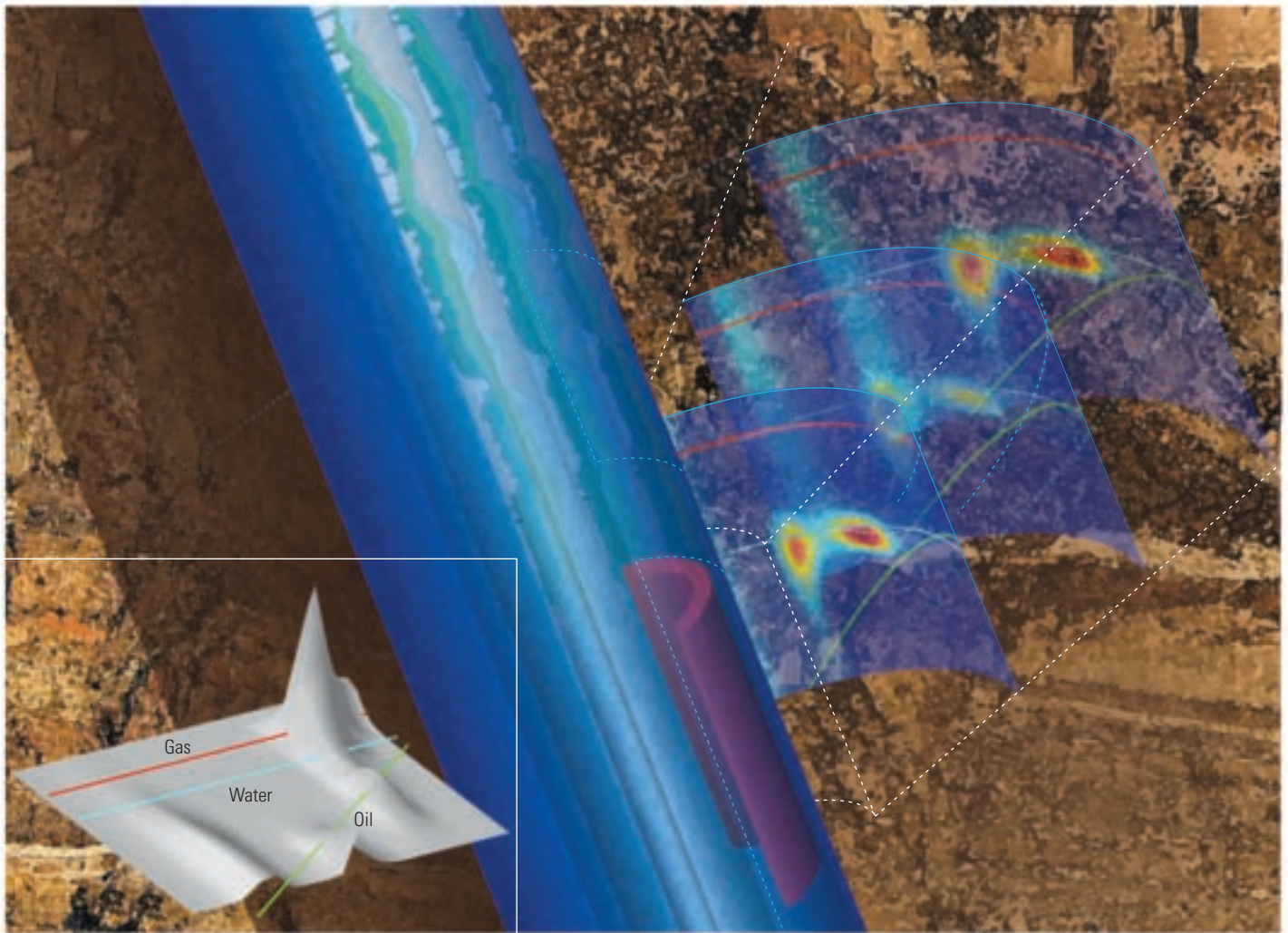
Magnetic resonance tools measure lithology-independent porosity and require no radioactive sources. They also provide permeability estimates and basic fluid properties. Initially, the fluid properties were limited to free-fluid volume and immovable clay- and capillary-bound fluid

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volumes. Although physicists were aware that much more information about the fluids could be coaxed from NMR data, downhole tools capable of providing more advanced acquisition and processing techniques were needed to extract fluid properties in a continuous log.

This article discusses developments in measurement techniques that provide NMR-based in situ formation-fluid properties. A recently introduced downhole tool capable of making these measurements in both continuous and stationary modes is described, along with NMR logging theory applicable to these new measurements.<sup>1</sup> With these new NMR capabilities, fluid-characterization measurements resolve interpretation ambiguities as demonstrated by case studies from South America, the North Sea, the Middle East and west Africa.

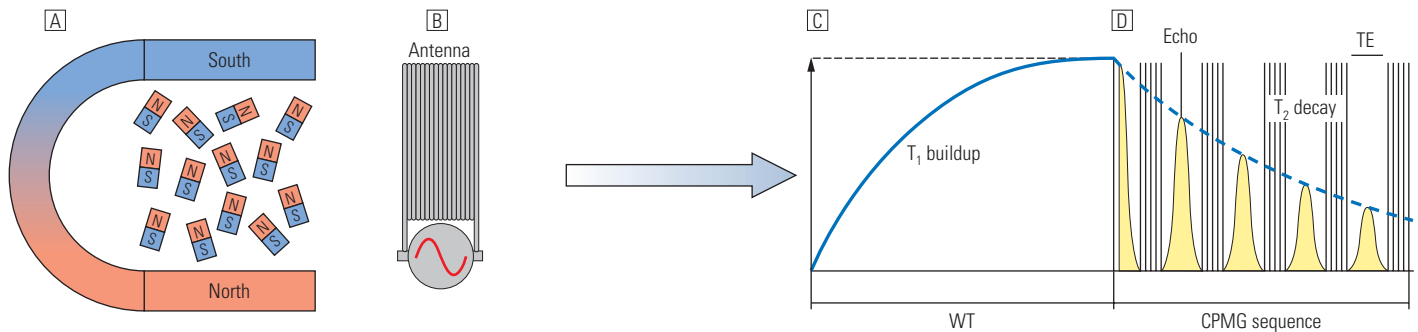
#### A Bit of Science

All NMR tools share some common features. They have strong permanent magnets that are used to polarize the spins of hydrogen nuclei found in reservoir fluids. The tools generate radio frequency pulses to manipulate the magnetization of hydrogen nuclei and then use the same antennas that generate those pulses to receive the extremely small RF echoes originating from the resonant hydrogen nuclei.

Because of their magnetic moments, hydrogen nuclei behave like microscopic bar magnets. Upon exposure to the static magnetic field,  $B_0$ , of the NMR tool's permanent magnets, the hydrogen's magnetic moments tend to align in the direction of  $B_0$ . Exposure time is referred to as the wait time, WT, and the time required for polarization to occur is influenced by various

formation and fluid properties. The buildup in the resulting magnetization is represented by a multicomponent exponential curve, each component of which is characterized by a  $T_1$  relaxation time.

1. For more on NMR theory and logging:  
Kenyon B, Kleinberg R, Straley C, Gubelin G and Morriss C: "Nuclear Magnetic Resonance Imaging—Technology for the 21st Century," *Oilfield Review* 7, no. 3 (Autumn 1995): 19–33.  
Allen D, Cray S, Freedman B, Andreani M, Klopff W, Badry R, Flaum C, Kenyon B, Kleinberg R, Gossenberger P, Horkowitz J, Logan D, Singer J and White J: "How to Use Borehole Nuclear Magnetic Resonance," *Oilfield Review* 9, no. 2 (Summer 1997): 34–57.  
Allen D, Flaum C, Ramakrishnan TS, Bedford J, Castelijn K, Fairhurst D, Gubelin G, Heaton N, Minh CC, Norville MA, Seim MR, Pritchard T and Ramamoorthy R: "Trends in NMR Logging," *Oilfield Review* 12, no. 3 (Autumn 2000): 2–19.



^ Basic NMR theory. Hydrogen nuclei behave like tiny bar magnets and tend to align with the magnetic field of permanent magnets, such as those in an NMR logging tool (A). During a set wait time (WT), the nuclei polarize at an exponential buildup rate,  $T_1$ , comprising multiple components (C). Next, a train of RF pulses manipulates the spins of the hydrogen nuclei causing them to tip  $90^\circ$  and then precess about the permanent magnetic field. The formation fluids generate RF echoes between successive pulses, which are received and measured by the antenna of the NMR tool (B). The time between pulses is the echo spacing (TE) (D). The amplitudes of the echoes decay at a superposition of exponential relaxation times,  $T_2$ , which are a function of the pore-size distribution, fluid properties, formation mineralogy and molecular diffusion (E). An inversion technique converts the decay curve into a distribution of  $T_2$  measurements (F). In general, for brine-filled rocks, the distribution is related to the pore sizes in the rocks (G).

After a given WT, a train of electromagnetic RF pulses manipulates the magnetic moments of the hydrogen nuclei and tips their direction away from that of the  $B_0$  field. The process of sending long trains of RF pulses is referred to as a CPMG sequence.<sup>2</sup> A key feature of this sequence is alternating the polarity of the received signal to eliminate electronics-related artifacts. During the CPMG measurement cycle, the hydrogen nuclei in the formation generate detectable RF echoes at the same frequency used to manipulate them.<sup>3</sup> The echoes occur between RF bursts. The time between bursts is the echo spacing, TE.

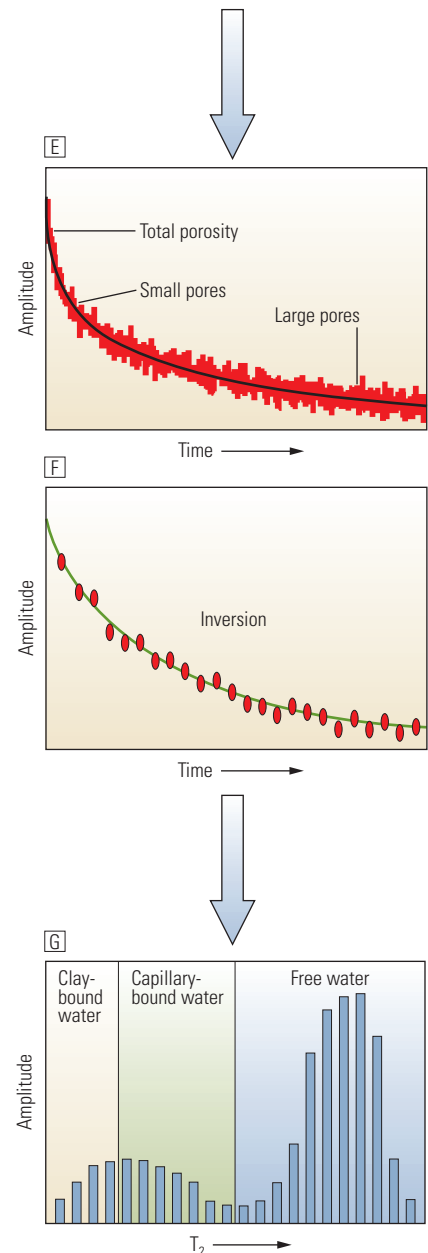
The amplitude of the echoes is proportional to the net magnetization in the plane transverse to the static field created by the permanent magnets. The amplitude of the initial echo is directly related to the formation porosity. The strength of the subsequent echoes decreases exponentially during the measurement cycle. The exponential decay rate, represented by the relaxation rate,  $T_2$ , is primarily a function of pore size, but also depends on the properties of the fluid in the reservoir, the presence of paramagnetic minerals in the rock and the diffusion effects of the fluids. In typical cases, the decay of the echo amplitudes is governed by a distribution of  $T_2$  times, similar to the  $T_1$  times found in the buildup curve. An inversion technique fits the decay curve with discrete exponential solutions. These solutions are converted to a continuous distribution of the

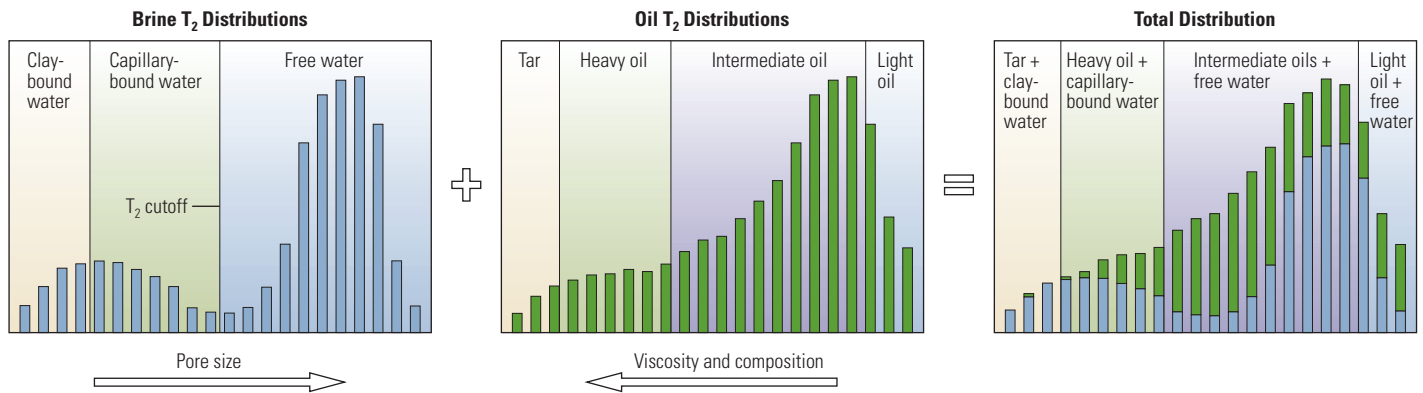
relaxation times representative of the fluid-filled pores in the reservoir rock (above).<sup>4</sup>

When the fluid in the sensed region is brine, the  $T_2$  distribution is generally bimodal, particularly in sandstones. Small pores and bound fluid have short  $T_2$  times, and free fluids in larger pores have longer relaxation times. The dividing line between bound and free fluid is referred to as the  $T_2$  cutoff. Oil and gas in the pore spaces introduce a few complications into the model.

The three primary mechanisms that influence  $T_2$  relaxation times are grain surface relaxation, relaxation by bulk-fluid processes and relaxation from molecular diffusion.<sup>5</sup> Grain surface relaxation is a function of pore-size distribution. Relaxation effects from molecular diffusion and bulk-fluid properties are directly related to the type of fluid in the pores.

Tar has an extremely short relaxation time and may not be measurable with downhole NMR tools. Heavy oils have short relaxation times, similar to those of clay- and capillary-bound fluids, but may also be too short for NMR acquisition (next page). Lighter oils have longer  $T_2$  times, similar to those associated with free fluids. Gas has an even longer relaxation time than oil. During the measurement process, oil and gas signals are detected along with signals from movable and irreducible water. While the  $T_2$  times from the oil and gas signals may have no relationship to the producibility of the





^ The effects of oil on  $T_2$  distributions. For brine-filled pores, the  $T_2$  distribution generally reflects the pore-size distribution of the rock. This distribution is often bimodal, representing small and large pores (left). The small pores contain clay- and capillary-bound fluids and have short relaxation times. The large pores contain movable free water and have longer relaxation times. The dividing line between bound and free fluids is the  $T_2$  cutoff. When oil fills the reservoir pore spaces, the measured  $T_2$

distribution is determined by the viscosity and composition of the oil (middle). Because of their molecular structure, tar and viscous heavy oils have fast decay rates, or short  $T_2$  times. Lighter oils and condensate have a spectrum of  $T_2$  times, overlapping with those of larger brine-filled pores. Mixed oil and water in the reservoir result in a combination of  $T_2$  times based on both pore size and fluid properties (right).

hydrocarbons, they do help characterize the fluid type. Techniques have been developed to exploit the fluid response and identify the presence and type of hydrocarbons.

In the past, there were two primary techniques by which NMR data were used to identify fluids: differential spectrum and enhanced diffusion.<sup>6</sup> The differential spectrum technique combines measurements with two different wait times. Short WTs underpolarize formation fluids, such as gas and light oil, which have long buildup and decay times. Measurements from fluids with short relaxation times are not affected by a change in WT. Differences between sequential logging passes identify the presence of light hydrocarbon, making the differential spectrum technique most effective in gas or condensate environments. Logging sequences have also been developed that acquire the data in a single pass.

Enhanced diffusion exploits changes in fluid response that occur when different echo spacings, or TEs, are used.<sup>7</sup> Water and oil generally have similar relaxation times when measurements are

acquired using short TEs, but water often relaxes faster than oil when longer TEs are used. To isolate the oil signal, a measurement with a short TE is compared with an echo train with a longer TE, chosen to enhance the diffusion differences of the fluids in the formation. The water signal decreases with longer TEs, leaving primarily the oil signal. This diffusion sensitivity provides a qualitative indication of the presence of oil, although the measurement may sometimes be quantitative as well.<sup>8</sup>

Both differential spectrum and enhanced diffusion rely on traditional  $T_2$  relaxation measurements to identify hydrocarbons. This limits the results to a one-dimensional aspect of the fluids, and fluid type can only be inferred, not directly quantified. Also, prior knowledge of the expected fluids is necessary to choose the correct acquisition parameters. The primary limitation of the relaxation dimension is the difficulty in distinguishing water from oil (see "Dimensions in NMR Logging," next page). But, the fact that oil and gas signals are included with the water signal

in the total distribution introduces an exploitable dimension to the relaxation distributions. Remove the water contribution and only the hydrocarbon signal remains.

Molecular diffusion is the key to unlocking fluid properties from the NMR data. Gas and water have characteristic diffusion rates that can be calculated for given downhole conditions. Oil has a range of diffusion values based on its molecular structure. This range can also be predicted from empirical data derived from dead-oil samples.

The  $T_2$  measurement provides the total volume of fluid—bound and free. The addition of diffusion discriminates the type of fluid present. A graphical presentation—the diffusion- $T_2$ , or  $D$ - $T_2$ , map—displays these data in a 2D space formed by the diffusion dimension and the relaxation dimension. The water signal can be separated from that of the hydrocarbons. The intensity of the components in the  $D$ - $T_2$  map provides fluid saturations. Maps can also be generated using  $T_1$  relaxation data.

This quantification of diffusion is made possible by a new acquisition technique, diffusion editing (DE), which alleviates the limitations of previous methods, such as enhanced diffusion and differential spectrum. Distinguishing water and hydrocarbon by their diffusivity differences not only permits the

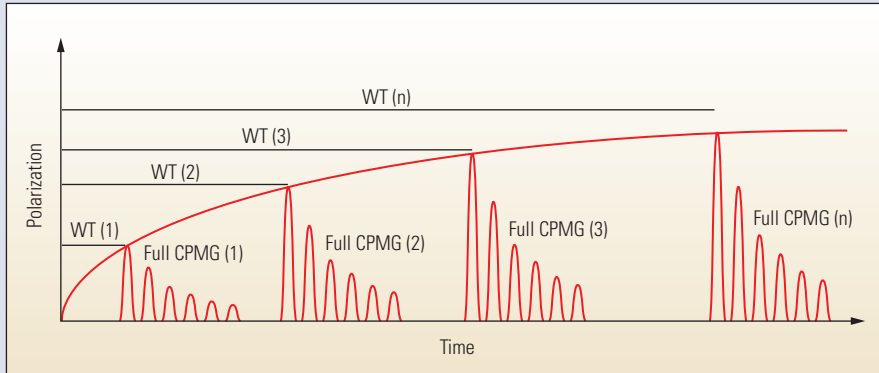
(continued on page 13)

2. CPMG refers to the physicists who successfully deployed the RF pulse sequence used in NMR devices—Herman Carr, Edward Purcell, Saul Meiboom and David Gill.
3. During the CPMG sequence, hydrogen atoms are manipulated by short RF bursts from an oscillating electromagnetic field. The frequency of the RF pulses is the Larmor frequency.
4. Freedman R and Heaton N: "Fluid Characterization Using Nuclear Magnetic Resonance Logging," *Petrophysics* 45, no. 3 (May–June 2004): 241–250.
5. Kleinberg RL, Kenyon WE and Mitra PP: "On the Mechanism of NMR Relaxation of Fluids in Rocks," *Journal of*

*Magnetic Resonance* 108A, no. 2 (1994): 206–214.

6. Akkurt R, Vinegar HJ, Tutunjian PN and Guillory AJ: "NMR Logging of Natural Gas Reservoirs," *The Log Analyst* 37, no. 6 (November–December 1996): 33–42.
7. Akkurt R, Mardon D, Gardner JS, Marschall DM and Solanet F: "Enhanced Diffusion: Expanding the Range of NMR Direct Hydrocarbon-Typing Applications," *Transactions of the SPWLA 39th Annual Logging Symposium*, Houston, May 26–29, 1998, paper GG.
8. Looyestijn W: "Determination of Oil Saturation from Diffusion NMR Logs," *Transactions of the SPWLA 37th Annual Logging Symposium*, New Orleans, June 16–19, 1996, paper SS.

## Dimensions in NMR Logging



^  $T_1$  logging. Traditional NMR CPMG sequences measure  $T_2$  distributions and begin after a sufficient WT for polarization of hydrogen nuclei. For  $T_1$  acquisition, a succession of short CPMG cycles with WTs selected over a range of values is used. In a departure from earlier  $T_1$  acquisition methods, the MR Scanner tool acquires full  $T_2$  echo trains for each chosen WT value, and thus the resulting data can be subjected to a multidimensional inversion and provide both  $T_1$  and  $T_2$  distributions.  $T_1$  logging is especially useful in low signal-to-noise environments and for fluids with long polarization times, such as are found with light hydrocarbons and in large pores. In addition,  $T_1$  distributions, unlike  $T_2$  distributions, are free of diffusion effects and provide more-accurate results in highly diffusive fluids.

Humans generally visualize in three dimensions, and geometric relationships are understood as adding levels of complexity with each dimension. For instance, a 1D image may have length, 2D adds width, 3D adds depth, and 4D adds the element of time.<sup>1</sup> Analogous to spatial relationships, NMR measurements can be described using dimensionality, with each dimension adding a degree of complexity.

The 1D NMR distribution refers to  $T_2$  transverse relaxation time measurements.  $T_2$  distributions are obtained by inverting raw NMR echo-decay signals. The distributions contain information about both fluid properties and pore geometry. However, signals from different fluids often overlap, and it is not always possible to distinguish water from oil, or water from gas purely on the basis of the  $T_2$  distribution.

The  $T_1$  relaxation measurement, from the buildup of polarization, also provides a 1D distribution. A single echo (or a small number of echoes) is acquired for a series of different wait times, WTs.<sup>2</sup> The observed increase in echo amplitude with increasing WT is the polarization buildup, which is governed by the distribution of  $T_1$  relaxation times (above). With a mathematical inversion similar to the one employed to derive  $T_2$  distributions from echo-decay signals, the  $T_1$  distribution is extracted from the polarization buildup.

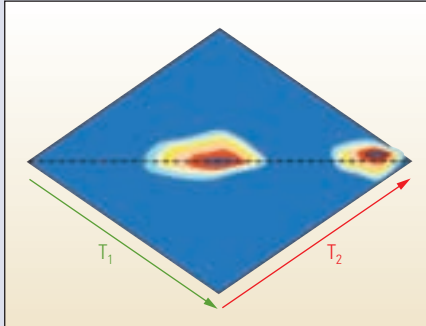
During the  $T_1$  acquisition, a full  $T_2$  echo-decay signal can be acquired for each WT, rather than a single echo or a short series of echoes, and thus a 2D dataset can be generated with  $T_2$  and  $T_1$  data. The individual echo-decay signals are inverted to obtain a separate  $T_2$  distribution for every WT. Each  $T_2$  component follows its own characteristic buildup with increasing WT, governed by the  $T_1$  distribution (buildup) associated with that

$T_2$  component. In practice, a 2D inversion directly transforms the original echo dataset to a 2D  $T_1$ - $T_2$  distribution, sometimes referred to as a  $T_1$ - $T_2$  map (next page, top left).<sup>3</sup>

For many fluids,  $T_1$  and  $T_2$  distributions are very similar since they are governed by the same physical properties. Under typical measurement conditions the  $T_1/T_2$  ratio for water and oil ranges between 1 and 3. However, an important difference between the two relaxation times is that  $T_2$  times are affected by molecular diffusion whereas  $T_1$  times are free of diffusion effects. In NMR measurements, diffusion causes a reduction in echo amplitude and therefore shortens  $T_2$  times. The magnitude of the diffusion effect is a function of the molecular-diffusion constant of the fluid,  $D$ , and the echo spacing, TE. TE is an adjustable measurement parameter defining the time between consecutive radio frequency (RF) pulses in the measurement sequence.

Diffusivity is an intrinsic fluid property, depending only on the fluid composition, temperature and pressure. Once quantified, it identifies the fluid type.<sup>4</sup> For water,  $D$  is primarily related to temperature, and for natural gas, it is determined by both temperature and pressure. Crude oils exhibit a distribution of diffusion rates governed by the molecular composition, temperature and pressure. Diffusion, therefore, is the key to identifying fluid type with NMR. For example,  $T_2$  relaxation times for gas are much shorter than  $T_1$  times because of diffusion. By identifying the difference between  $T_1$  and  $T_2$  measurements in a gas reservoir, the hydrocarbon type can be inferred.

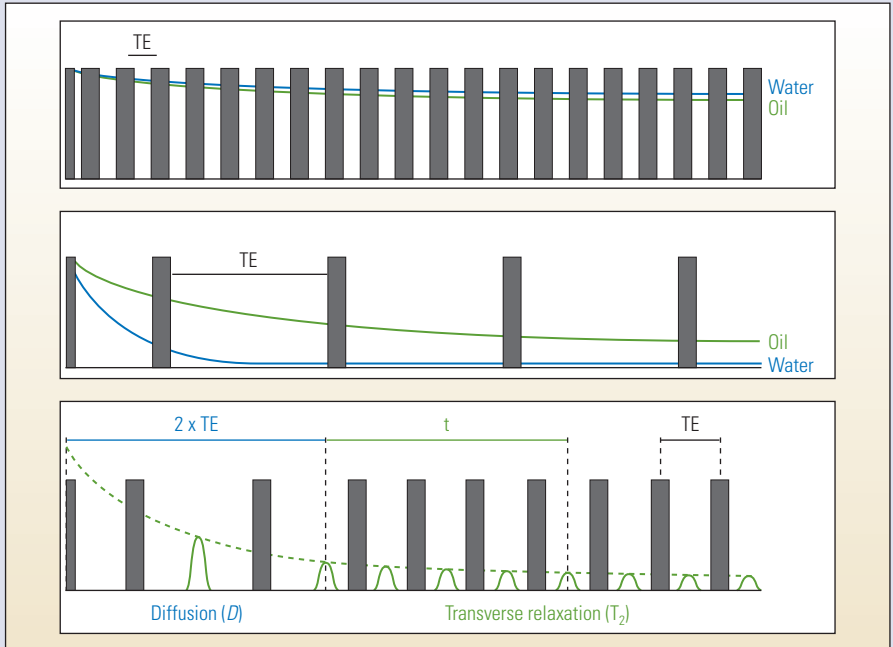
Diffusion distributions are determined by measuring echo-amplitude decays for echo trains acquired with different echo spacings, TEs. However, increasing the TE to allow diffusion to take place comes at a price. The increased time between echoes means there



^ Two-dimensional NMR data. The 2D nature of  $T_1$ - $T_2$  maps is highlighted by overlapping signals from the two sets of distributions. The crossplotted signals are at maxima, indicated by the color variation from blue to dark red, in the center and right of this plot. The data converge along the center line in the middle—their agreement indicating similar fluid measurements from both  $T_1$  and  $T_2$ . But, divergence of the longer time components of the two sets of data, resulting from molecular diffusion, moves the plot away from the center line at the right corner. If there were no diffusion effects, the crossplot would be centered along the dividing line.

are fewer echoes over an equivalent time span, reducing the data density. This also results in more rapid signal decay— $T_2$  times are shorter—because of the diffusion effects. The end result is a reduction in the amount of usable data, and the inversion becomes more challenging because of the lower signal-to-noise ratio.

The diffusion-editing (DE) technique overcomes these limitations by combining two long initial TEs—during which diffusion is effective in reducing the NMR signal—followed by an extended train of short TEs, during which diffusion effects are minimized (above right). A large number of echoes can



^ Diffusion editing. With traditional CPMG sequences and short echo spacing (TE), oil (green) and water (blue) signals relax, or decay, at similar rates (top). Lengthening the TE value (middle) enhances the diffusion effect preferentially for the fast-diffusing water compared with slower-diffusing oil. However, long TEs correspond to fewer echoes and a lower signal-to-noise ratio. Diffusion editing (bottom) is a variant of the multi-TE CPMG method, where only the first two echoes are lengthened to enhance the diffusion effect, while maintaining the advantage of the short TE for better signal-to-noise ratio.

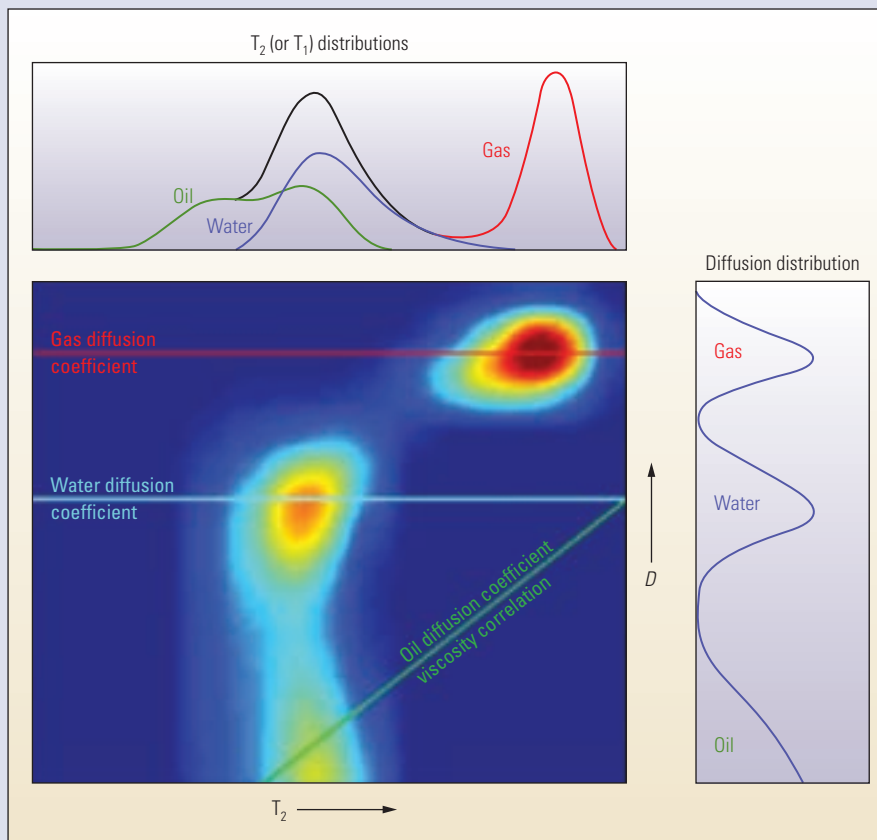
be acquired, and the effective signal-to-noise ratio is maximized.

Analogous to the  $T_1$ - $T_2$  measurement described earlier, a 2D experiment can be designed to extract diffusion information.

1. Beyond classical physics, there are other applications that describe four dimensions and beyond. String theory, for example, predicts 10 dimensions, including a zero dimension.
2. The wait time is the time allotted for the alignment of protons within the static magnetic field of the permanent magnet of an NMR logging tool during the measurement cycle.

Rather than acquiring echo trains for a number of sequential WTs, an echo train is acquired with different initial long TEs. The data are subjected to the inversion processing and can then be used to generate  $D$ - $T_2$  maps,

3. Song YQ, Venkataraman L, Hürlimann MD, Flaum M, Frulla P and Straley C: "T1-T2 Correlation Spectra Obtained Using a Fast Two-Dimensional Laplace Inversion," *Journal of Magnetic Resonance* 154, no. 2 (February 2002): 261–268.
4. Freedman and Heaton, reference 4, main text.



^ D-T maps. Diffusion plotted with T<sub>2</sub> (or T<sub>1</sub>) provides 2D reservoir-fluid maps that can resolve oil, gas and water. In this example, the diffusion dimension (*right*) is the key to identifying the fluids, which otherwise overlap in the T<sub>2</sub> dimension (*top left*). The amplitudes of the signals along one direction of the two-dimensional map result in 1D distributions, which then can be converted to fluid saturations. As an aid to interpreting the 2D maps, fluid-diffusion coefficients are superimposed on the map (*bottom left*). The gas line (red) is computed using downhole pressure and temperature inputs. The water line (blue) is calculated using the downhole formation temperature. The oil line (green) shows the position of oil at different viscosities, with the lower left being heavy oil, trending to light oil and condensate at the upper right. The interpretation of this map is that the reservoir contains gas, oil and water.

which are a graphical means to identify fluid type and quantify saturations (*above*).<sup>5</sup>

Although the two-dimensional D-T<sub>2</sub> measurement is effective in separating the oil signal from that of the water, it is less robust for distinguishing between highly diffusive

fluids, such as gas, condensate or water at high temperatures. The problem arises because diffusion can dominate the T<sub>2</sub> relaxation mechanism for these fluids, even at the shortest echo spacing available from the logging tools. The underlying “diffusion-free”

5. Hürlimann MD, Venkataraman L, Flaum C, Speier P, Karmonik C, Freedman R and Heaton N: “Diffusion-Editing: New NMR Measurement of Saturation and Pore Geometry,” *Transactions of the SPWLA 43rd Annual Logging Symposium*, Oiso, Japan, June 2–6, 2002, paper FFF.

6. Freedman and Heaton, reference 4, main text.

7. Cao Minh C, Heaton N, Ramamoorthy R, Decoster E, White J, Junk E, Eyvazzadeh R, Al-Yousef O, Fiorini R

and McLendon D: “Planning and Interpreting NMR Fluid-Characterization Logs,” paper SPE 84478, presented at the SPE Annual Technical Conference and Exhibition, Denver, October 5–8, 2003.

8. For more on wettability: Abdallah W, Buckley JS, Carnegie A, Edwards J, Herold B, Fordham E, Graue A, Habashy T, Seleznev N, Signer C, Hussain H, Montaron B and Ziauddin M: “Fundamentals of Wettability,” *Oilfield Review* 19, no. 2 (Summer 2007): 44–61.

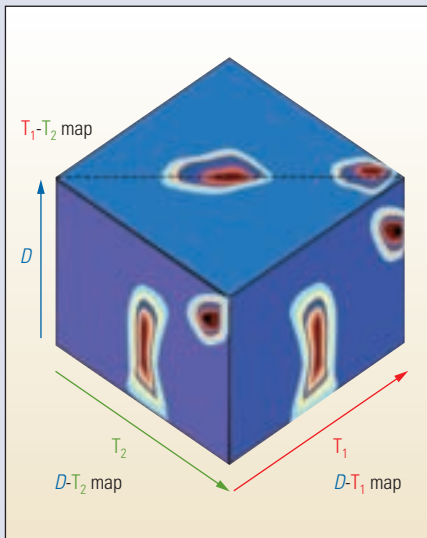
T<sub>2</sub>, which contains important complementary information about composition, such as gas/oil ratio (GOR) and pore-size information for water, cannot be measured. This limitation is overcome by invoking a third dimension to combine with diffusion, T<sub>1</sub> relaxation times.<sup>6</sup>

The 3D NMR measurements acquire echo-train data at multiple WTs (for T<sub>1</sub>) and multiple TEs (for diffusion). Sufficient information is then available to create 3D maps of D-T<sub>1</sub>-T<sub>2</sub>, in which the T<sub>2</sub> axis refers to a transverse relaxation time with diffusion effects removed (*next page, left*). The map is therefore a 3D correlation of intrinsic fluid properties for T<sub>1</sub>, T<sub>2</sub> and D. In practice, NMR fluid maps are typically presented in a 2D format, plotting D with either T<sub>1</sub> or T<sub>2</sub>, or on occasion plotting T<sub>1</sub> with T<sub>2</sub>.

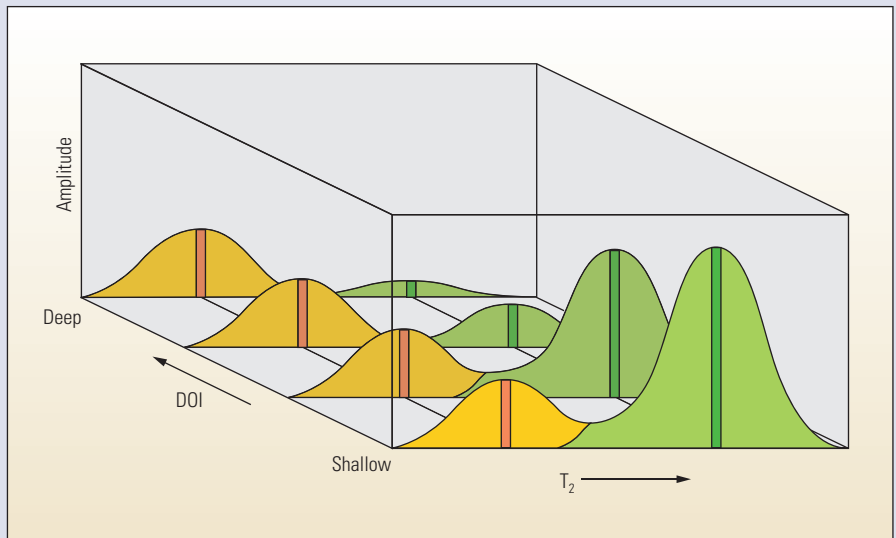
Overlain on the maps are default fluid-response lines for the D of gas and water computed from their diffusion coefficient at formation temperature and pressure. The oil line is derived from the estimated dead-oil response at downhole conditions.

The fourth dimension in NMR logging, the radial distance from the borehole wall, results from acquisition at multiple depths of investigation (DOIs). Data from two or three DOIs are simultaneously inverted. Results from the shallow DOI are used to correct data from deeper DOIs, improving the outputs affected by missing information and poorer signal-to-noise ratios.

NMR logging tools acquire data from a region often affected by filtrate invasion, which alters the original fluid distribution. The 4D NMR processing is based on the assumptions that bound-fluid volume and immovable hydrocarbon volume are invariant to DOI. The shallow-measurement data are used to constrain the inversion for the deeper measurements by fixing the bound-fluid components. (For examples of 4D NMR processing, see pages 16 and 17.) Diffusion and T<sub>1</sub> (or T<sub>2</sub>) data from 4D NMR are used to produce fluid maps at multiple DOIs. Fluid changes that take place as filtrate invades the reservoir rock are graphically displayed and



^ Three dimensions of NMR. Diffusion,  $T_1$  distributions and  $T_2$  distributions presented in a 3D format provide intrinsic fluid properties. The cube is used to identify diffusion effects and may aid the interpreter in deciding which model best describes the fluid properties.



^ NMR in four dimensions. The fourth dimension of NMR logging is depth. Bound-fluid volumes, associated with both clay- and capillary-bound fluids (yellow), do not generally change when filtrate from the drilling fluid invades the reservoir. Tool or measurement limitations, however, can result in changes in computed fluid properties that do not represent the true fluid distributions. Constraining the volumes of bound fluid measured by deeper-reading shells to be equivalent to that of the more-precise shallower shells and reappportioning the total porosity across the fluid spectrum provide more-accurate fluid analysis. Use of 4D NMR processing is especially beneficial in interpreting data from heavy-oil reservoirs.

allow petrophysicists to detect oil mobility, wettability effects and fluid interactions (above right).

Although the interpretation of maps created from 3D or 4D NMR data might seem simple, complications do exist. The results rely on a forward-model approach that assumes the fluid and the reservoir meet certain criteria. When nonideal fluid properties or atypical reservoir conditions are encountered, the response deviates from the model, and conflicting or erroneous results may ensue.<sup>7</sup> In some cases, nonideal effects can be detected and even quantified by inspection of the  $D$ - $T$  maps. Relevant parameters in the forward model can be adjusted once these effects are identified.

In another problem, when diffusion of fluid molecules in small pores is restricted, the measured values of diffusion are reduced from those of the ideal model (next page). While the signal from fluids in large pores

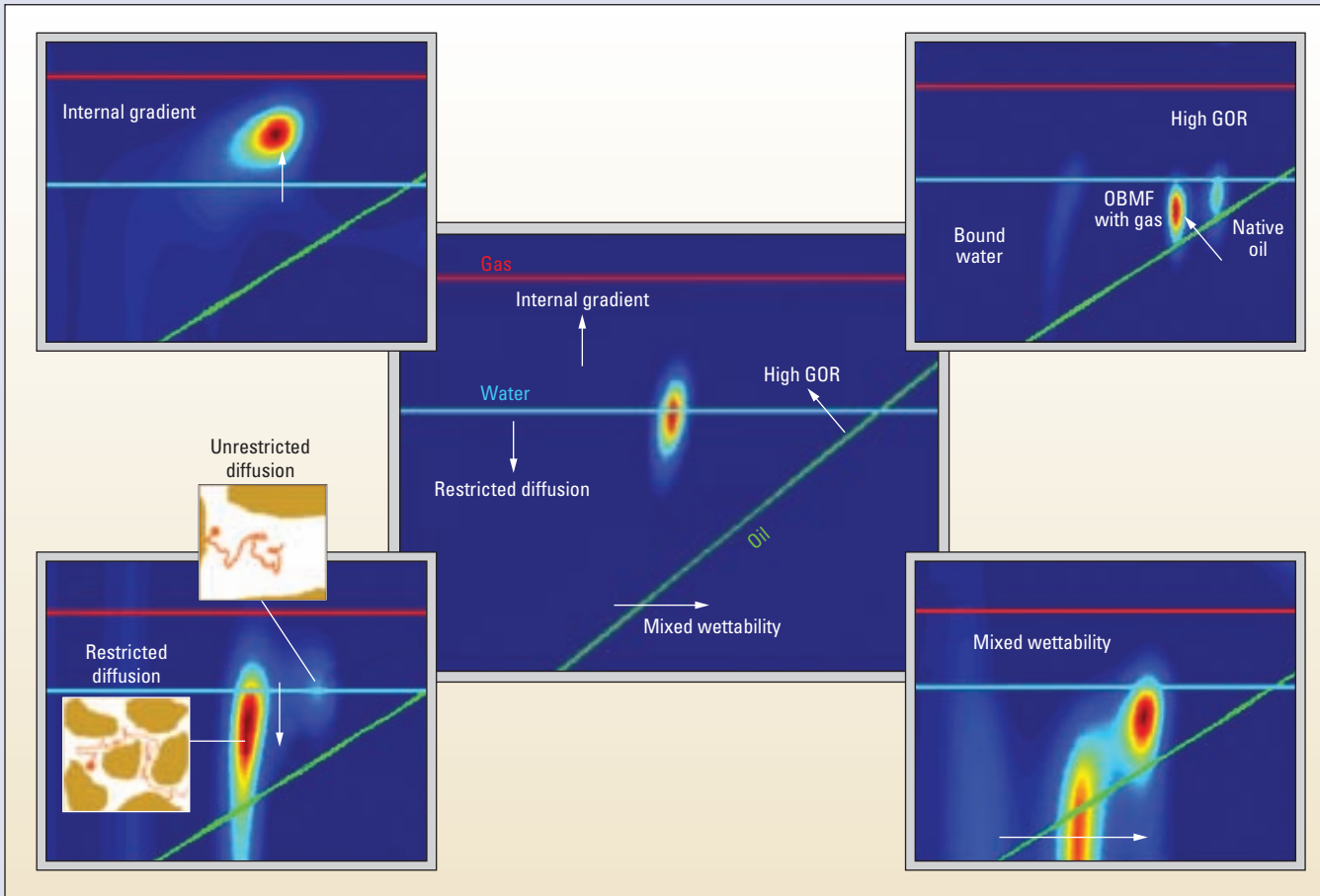
appears as expected in the  $D$ - $T$  maps, fluids in the small, poorly connected pores may plot at lower diffusivity values. The problem is most common for water diffusion in fine-grained carbonate rocks. If the effect is not identified, the calculated oil saturation may be overly optimistic. However, once the restricted-diffusion effect is detected, model parameters can be adjusted according to the observed 2D map results and fluid-saturation estimations corrected.

Another anomalous effect results from internal magnetic-field gradients caused by paramagnetic and ferromagnetic materials in the rocks, either in the matrix or coating the grains. These are often associated with high chlorite content and create significant localized field gradients, resulting in faster relaxation times. Because the inversion model is based on the tool's fixed magnetic-field gradient, the  $D$ - $T$  map responses of the fluids in these rocks are shifted to higher diffusion

rates, the opposite of the restricted-diffusion effect. For example, water signals may appear above the water line. Fortunately, it is usually possible to identify these effects by inspection of the maps, and model parameters can then be adjusted to provide correct interpretations.

The wettability state also affects  $D$ - $T$  maps. Under water-wet conditions, the oil viscosity determines the position of the oil signal along the oil line of the map. The trend is from heavy oil at the bottom left to lighter oils and condensate at the top right of the line. Oil-wet rocks and those with mixed wettability tend to have shorter relaxation times because of the additional surface relaxation of the hydrocarbon in direct contact with the pore surface. Although this can compromise the accuracy of oil viscosity estimated from the NMR data, it can also be a useful measurement for petrophysicists in understanding the nature of the reservoir.<sup>8</sup>





^ Interpreting the maps. After inversion, two-dimensional crossplots of the data identify the presence of oil, water and gas. When the plot of the response from formation fluids (shown as color contours) conforms to the interpretation model, the response will fall on or near the expected gas, oil or water lines. This affords a straightforward interpretation. Water falls on the water line as shown (*middle*). However, signals frequently fall off the lines as a result of competing petrophysical effects, which include internal gradients, restricted diffusion, wettability and high gas/oil ratios (GOR). Because internal gradients shorten the relaxation times, the plots tend to shift upward (*top left*). Restricted diffusion causes the measured diffusion rate to increase, and, as a consequence, the plots will trend down and away

from the expected fluid line (*bottom left*). Plots from oil-wet reservoirs tend to shift to the right of the oil line, as do reservoirs with mixed wettability (*bottom right*). The maps from oil-wet and mixed-wet reservoirs tend to have a spectrum of responses, which produce a broader image. Because the model is built with dead-oil responses, maps from high-GOR oil reservoirs may not respond as expected. These plots are shifted away from the oil line toward the gas line (*top right*). In a reservoir that contains only gas, OBM filtrate may mix with the native gas and produce a response similar to that of high-GOR oil. Deeper measurements often help experts refine their interpretation of these maps because filtrate generally diminishes away from the wellbore and gas response increases.

Fluids with a high GOR tend to plot above and to the left of the oil line. This can be seen in native fluids and gas-bearing zones invaded by oil-base mud filtrate (OBMF). OBMF should plot as a moderate to light hydrocarbon. The response of OBMF mixed with native gas from the reservoir plots between the oil and water lines.

The D-T maps are powerful tools for interpreting fluid types in the reservoir. In many cases the interpretation is straightforward, but

consideration must be given to external factors that lead to nonideal behavior and mislead a novice interpreter. For this reason, it is important to rely on experts adequately trained in processing and interpreting NMR data.

A surgeon relies on a trained radiologist to interpret MRI images. A clean break of a bone is easy to spot, even by a novice user, but experience helps a radiologist differentiate between bone fragments and calcification. The differences may be indistinguishable to

the untrained eye. In a similar manner, the log analyst may easily determine the presence of water or gas in a D-T map, but there are occasions when a skilled NMR expert should be called in to help analyze the results. With the aid of fluid maps and an understanding of the measurement physics, the petrophysicist can diagnose conditions that are hidden from the inexperienced observer.

computation of fluid saturations, but also helps infer fluid viscosity from the  $T_2$  contribution of the fluid (right).

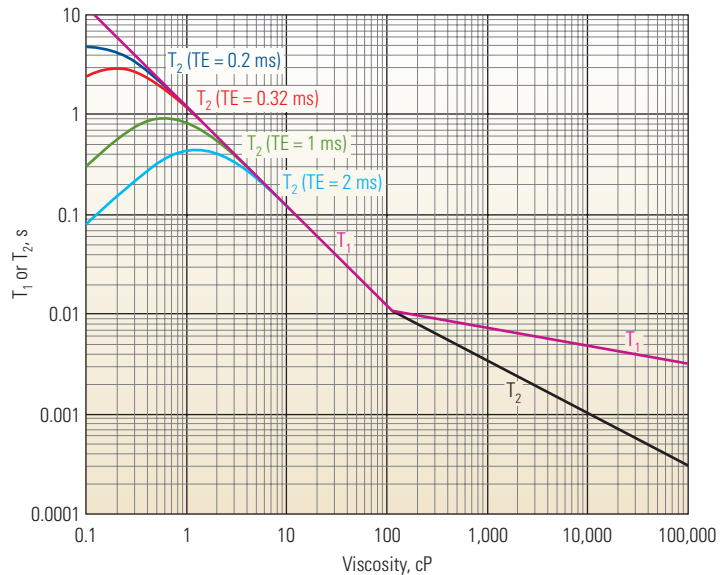
Diffusion-editing sequences from the new MR Scanner service supply a water-saturation output that is independent of that traditionally derived from resistivity and porosity measurements. In contrast to a saturation derived from Archie's equation, NMR-based saturation measurement techniques are useful in fresh water or formation waters of unknown salinity. Wettability can also be inferred from NMR data. One drawback to using NMR measurements for fluid characterization is that the measurement comes from a near-well region referred to as the flushed zone, where mud-filtrate effects are strongest.

### The MR Scanner Tool

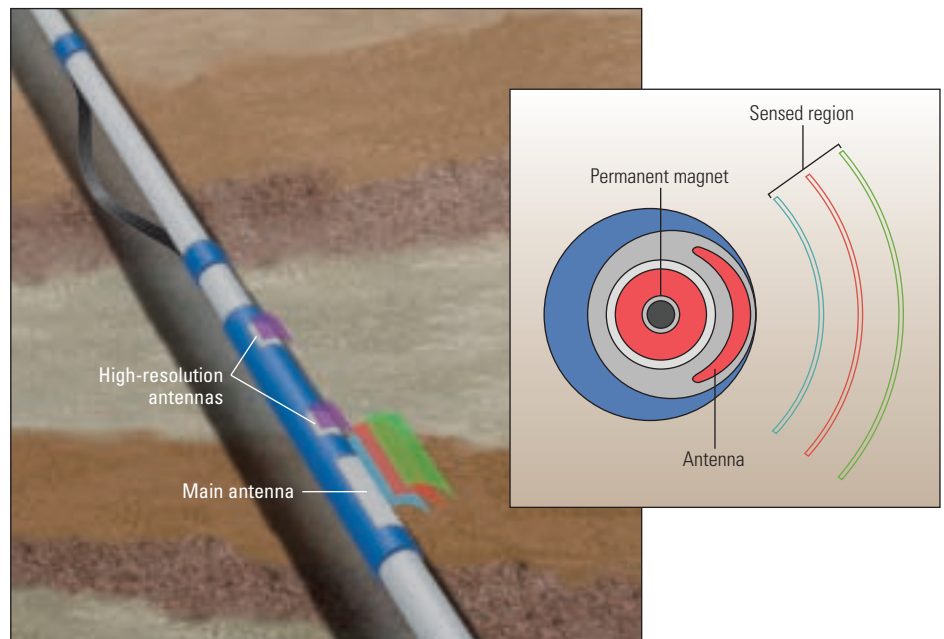
Although NMR measurements may come from only a few inches into the formation, they can still provide formation-fluid properties. To measure continuous in situ fluid characteristics—including fluid type, volume and oil viscosity—much more information is needed than was provided by previous-generation NMR tools.<sup>9</sup> For this reason, fluid characterization was a key driver in the development of the MR Scanner service.

In the past, there were two basic designs for NMR tools: pad-contact tools and centralized concentric-shell tools. The pad device, represented by the CMR tool, measures NMR properties of a cigar-sized volume of the reservoir fluids at a fixed depth of investigation (DOI) of approximately 1.1 in. [2.8 cm]. The NUMAR MRIL Magnetic Resonance Imager Log tool measures concentric cylindrical resonant shells of varying thickness and at fixed distances from the tool, with the DOI determined by hole size and tool position in the wellbore.

The MR Scanner design offers the fixed DOI of a pad device with the flexibility of multiple DOIs of resonant shells.<sup>10</sup> It consists of a main antenna optimized for fluid analysis and two shorter high-resolution antennas best suited for acquiring basic NMR properties (right). The main antenna operates at multiple frequencies corresponding to independent measurement volumes (shells) at evenly spaced DOIs.



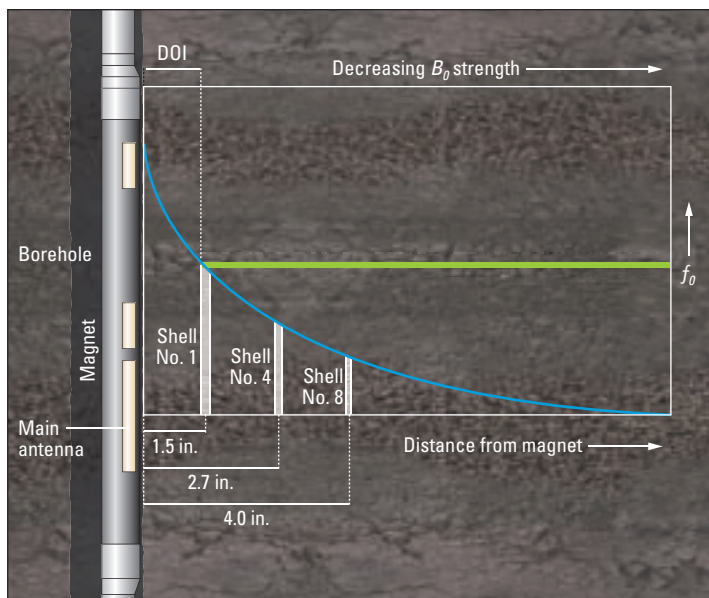
^ Viscosity transform. The  $T_2$  (or  $T_1$ ) relaxation time for crude oil is a function of viscosity. The relaxation time can be converted to viscosity using an empirically derived transform. Because of diffusion effects, the viscosity measurement for heavy oils below 3 cP [0.003 Pa.s] is influenced by the echo spacing (TE) of the measurement. Thus,  $T_2$  times may be tool dependent for heavy oils if the tool is not capable of shorter TEs. As a consequence of diffusion,  $T_1$  and  $T_2$  values in light oils diverge above 100 cP [0.1 Pa.s].



9. Heaton NJ, Freedman R, Karmonik C, Taherian R, Walter K and DePavia L: "Applications of a New-Generation NMR Wireline Logging Tool," paper SPE 77400, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, September 29–October 2, 2002.

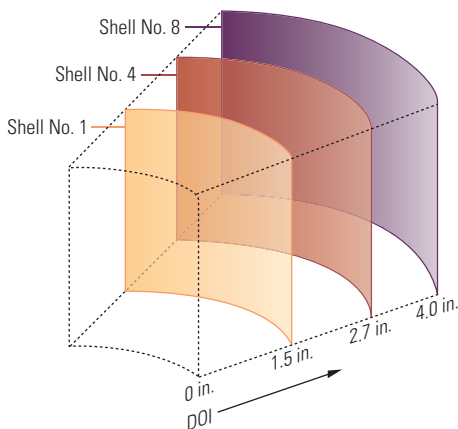
10. DePavia L, Heaton N, Ayers D, Freedman R, Harris R, Jorion B, Kovats J, Luong B, Rajan N, Taherian R, Walter K, Willis D, Scheibal J and Garcia S: "A Next-Generation Wireline NMR Logging Tool," paper SPE 84482, presented at the SPE Annual Technical Conference and Exhibition, Denver, October 5–8, 2003.

^ MR Scanner service. The MR Scanner tool has three antennas. The main antenna operates at multiple frequencies and is optimized for fluid-property acquisition. The sensed region consists of very thin shells that form arcs of approximately 100° in front of the 18-in. [46-cm] length of the antenna. The thickness of the individual shells is 2 to 3 mm. The two high-resolution antennas are 7.5 in. [19 cm] long and provide measurements with a DOI of 1.25 in. [3.17 cm]. The MR Scanner tool is run eccentric with the antenna section pressed against the borehole.



▲ Gradient tool and DOI. The MR Scanner tool is referred to as a gradient tool because the magnetic-field strength ( $B_0$ , blue) from the permanent magnet, although uniform over the sample region, decreases monotonically away from the magnet. The tool's magnet extends along the length of the sonde section. A constant, well-defined gradient simplifies fluid-property measurements. The DOI is determined by the magnetic-field strength and the frequency of RF operation,  $f_0$ . Although multiple frequencies are available from the tool, standard operating procedure is to acquire data from the 1.5-in., 2.7-in. and 4.0-in. DOI shells, referred to as Shell No. 1, Shell No. 4 and Shell No. 8, respectively. Three shells are shown, with their respective DOI-related operating frequencies. The frequency associated with Shell No. 1 is shown in green.

Although multiple frequencies are available from the main antenna, the three most commonly used are Shells No. 1, No. 4 and No. 8, which correspond to 1.5-in., 2.7-in. and 4.0-in.



▲ Radial profiling. The MR Scanner tool senses fluid from multiple, thin DOI shells. The spacing is optimized to avoid shell interaction. Fluid properties vary in the first few inches into the formation as a result of flushing by mud filtrate. Deeper shells are less affected by filtrate, mud invasion and borehole rugosity than are shallow-reading shells.

[3.8-cm, 6.8-cm and 10.2-cm] DOIs, respectively. A recently introduced three-shell simultaneous acquisition mode eliminates the need for multiple passes to acquire data from all three DOIs.

### Profiling Fluid Properties

The three primary frequencies commonly used by the MR Scanner tool correspond to three independent DOIs, providing measurements at discrete radial steps into the formation. The frequency of the RF pulse, along with the field strength of the magnet, determines the DOI of the shell (above). A key advantage of the MR Scanner shells is that the measurement comes from a thin cylindrical portion of the formation—an isolated slice—and is not generally affected by the fluids between the tool and the measurement volume. This allows interpretation of near-wellbore fluid properties in a manner that is unique in formation evaluation.

Multiple DOIs introduce new concepts for NMR logging—radial profiling and saturation profiling (left). Profiling incorporates measurements from successive DOIs to quantify changes in fluid properties occurring in the first few inches of formation away from the wellbore.

Borehole rugosity and thick mudcake can invalidate shallow NMR measurements but rarely affect the readings from the deeper shells. NMR porosity from a deep shell has been used as a substitute for formation density porosity when that measurement was compromised by borehole rugosity.

Fluid-property changes resulting from mud-filtrate invasion may also be observed and quantified using radial profiling. Often more than just filtrate from the drilling mud invades the formation. Whole mud and mud solids can replace existing fluids in the near-wellbore region. NMR-derived porosity and permeability may be reduced by the presence of these solids, but the effects diminish deeper into the formation. Radial profiling identifies and overcomes these effects.

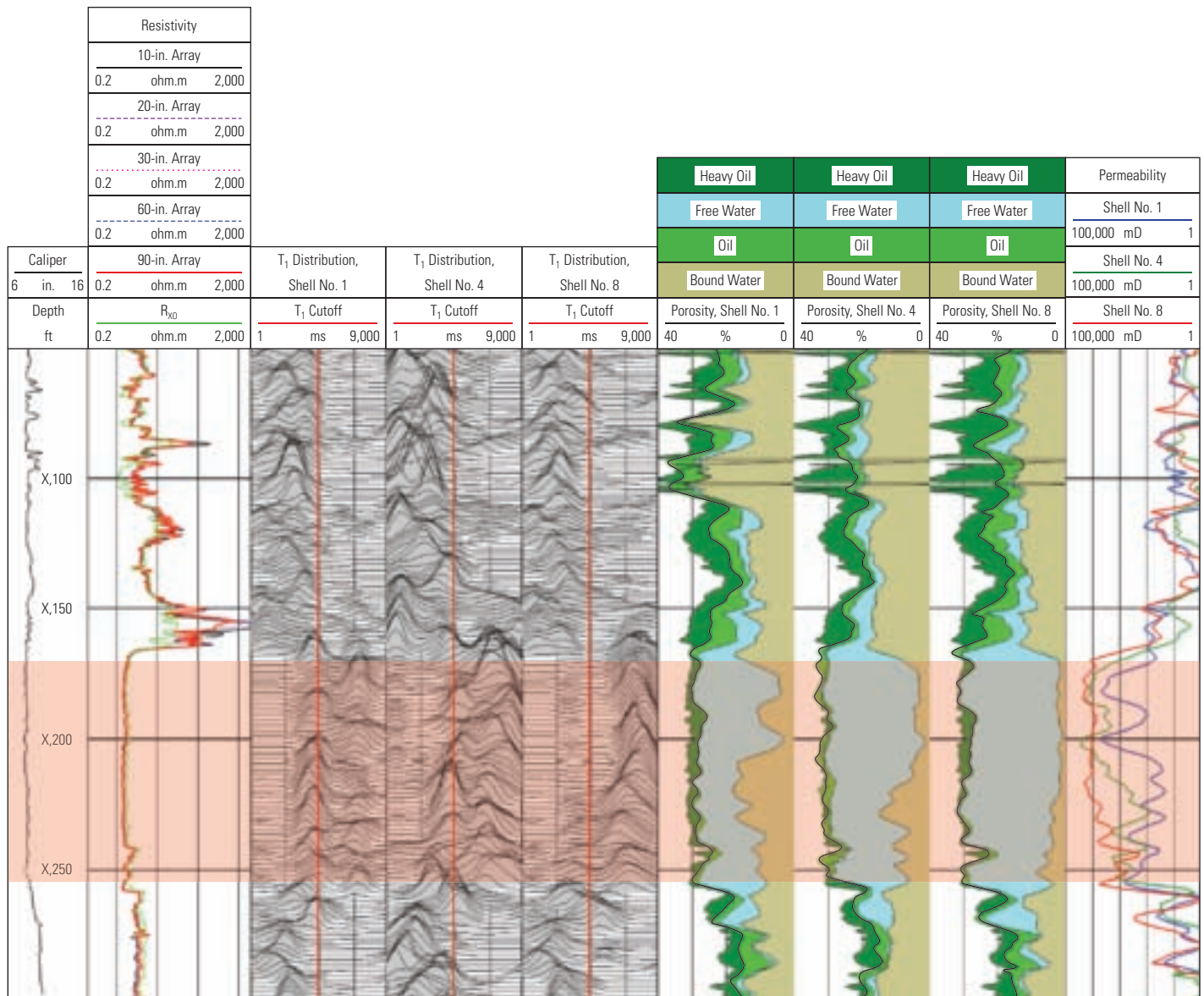
Saturation profiling delivers advanced fluid-characterization measurements such as oil, gas and water saturations, fluid type and oil viscosity—all at discrete multiple DOIs. One application of saturation profiling is the evaluation of heavy-oil reservoirs.

### Viscosity and Rugosity

Of the world's known reserves, 6 to 9 trillion barrels [0.9 to 1.4 trillion  $m^3$ ], are found in the form of heavy- or extraheavy-oil accumulations.<sup>11</sup> This is triple the amount of world reserves of conventional oil and gas combined. Heavy-oil reservoirs pose serious operational concerns for proper evaluation of fluids and production potential. Sampling with wireline-conveyed tools or drillstem tests may not be possible because of the difficulties in getting the oil to flow. NMR measurements can provide essential information on in situ fluid properties to evaluate heavy-oil reservoirs.

Located south of the Eastern Venezuelan basin, the Orinoco heavy-oil belt holds an estimated 1.2 trillion barrels [190 billion  $m^3$ ] of heavy oil. NMR logs have been an integral part of evaluation programs of the wells drilled in this region, but with recognized limitations.<sup>12</sup> The relaxation times of high-viscosity oils are very short and may not be fully measurable using NMR tools. Also, borehole conditions in the Orinoco basin are often poor, with rugosity that affects pad-contact tools.

Although the early introduction of NMR fluid characterization with the CMR tool showed promise, the measurements were limited to a single, shallow DOI. Techniques were developed to use NMR data to estimate the oil viscosity throughout a sand interval based on the logarithmic mean of  $T_2$  distributions. Encouraging



^ Radial profiling with filtrate and whole-mud invasion. The interval from X,170 to X,255 ft (red shading) is a clean water sand beneath a heavy-oil reservoir in the Orinoco heavy-oil basin. The fluid properties from the 1.5-in. DOI, Shell No. 1 (Track 5) have spurious volumes of bound water (light brown). Even at 2.7 in., Shell No. 4 indicates more bound fluid than expected for a clean sand (Track 6, light brown). The differences are attributed to whole-mud invasion. The Shell No. 8 data come from a region

beyond the whole-mud invasion and provide more-representative information (Track 7). The total porosity measurements from the three shells appear to be unaffected by the presence of whole mud. Permeabilities calculated from the shallower shells (Track 8, blue, green) are lower than that of the deepest shell (Track 8, red) because the measurements are affected by the solids that are filling the pore spaces.

results were obtained but fell short of true in situ viscosity. There was no calibrated transform to link the logarithmic mean of the T<sub>2</sub> distributions to the viscosity at downhole conditions that would also account for the apparent hydrogen index (HI) of the oil.<sup>13</sup> The importance of using HI and an empirical transform was demonstrated by recent laboratory work.<sup>14</sup>

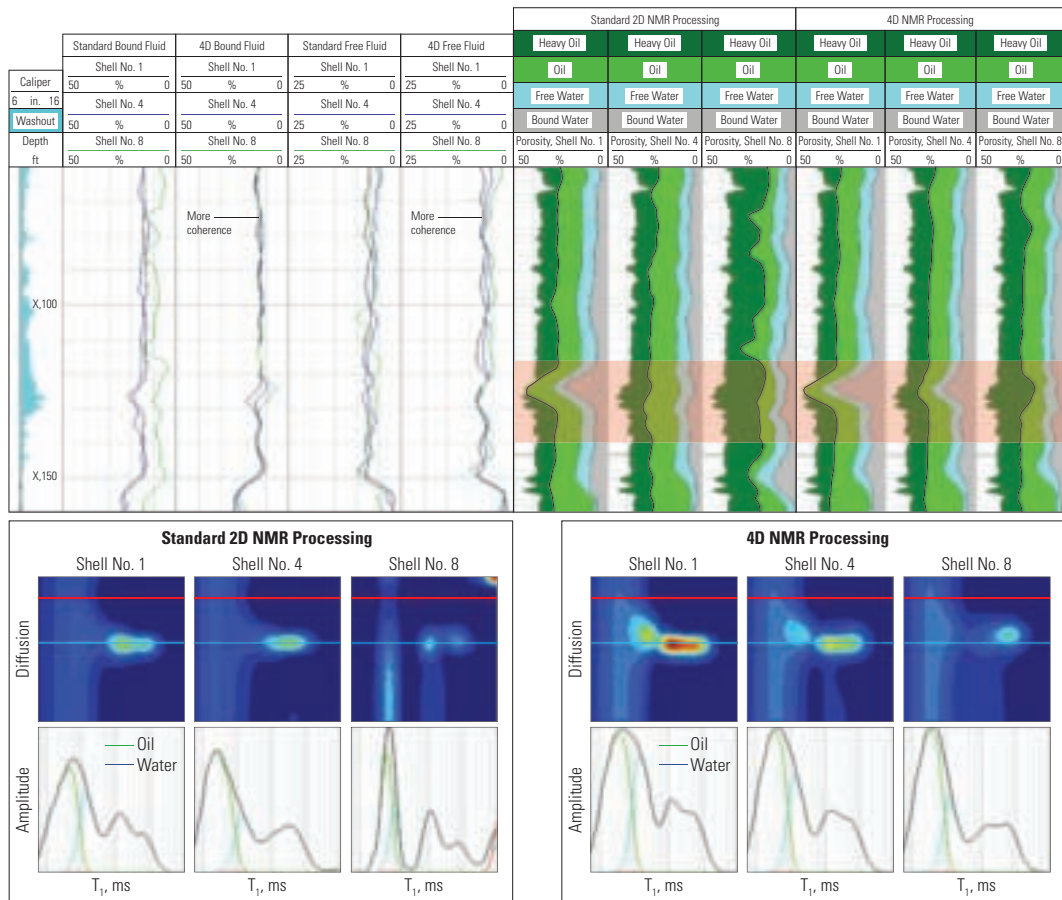
The MR Scanner tool was included in a more recent logging program, in part, to overcome some of the limitations of the CMR measurements. Radial profiling was found to be beneficial in zones where rugosity affected the 1.5-in. DOI

measurement from Shell No. 1, which is comparable to the CMR tool's DOI. The 2.7-in. measurement from Shell No. 4 was only slightly

affected by rugosity. The 4.0-in. Shell No. 8 data were not affected because they were acquired from a region beyond the rugosity (above).

- Alboudwarej H, Felix J, Taylor S, Badry R, Bremner C, Brough B, Skeates C, Baker A, Palmer D, Pattison K, Beshry M, Krawchuk P, Brown G, Calvo R, Cañas Triana JA, Hathcock R, Koerner K, Hughes T, Kundu D, López de Cárdenas J and West C: "Highlighting Heavy Oil," *Oilfield Review* 18, no. 2 (Summer 2006): 34–53.
- Decoster E and Carmona R: "Application of Recent NMR Developments to the Characterization of Orinoco Belt Heavy Oil Reservoirs," *Transactions of the SPWLA 49th Annual Logging Symposium*, Edinburgh, Scotland, May 25–28, 2008, paper VVV.

- Carmona R and Decoster E: "Assessing Production Potential of Heavy Oil Reservoirs from the Orinoco Belt with NMR Logs," *Transactions of the SPWLA 42nd Annual Logging Symposium*, Houston, June 17–20, 2001, paper ZZ.
- Burcaw L, Kleinberg R, Bryan J, Kantzas A, Cheng Y, Kharrat A and Badry R: "Improved Methods for Estimating the Viscosity of Heavy Oils from Magnetic Resonance Data," *Transactions of the SPWLA 49th Annual Logging Symposium*, Edinburgh, Scotland, May 25–28, 2008, paper WV.



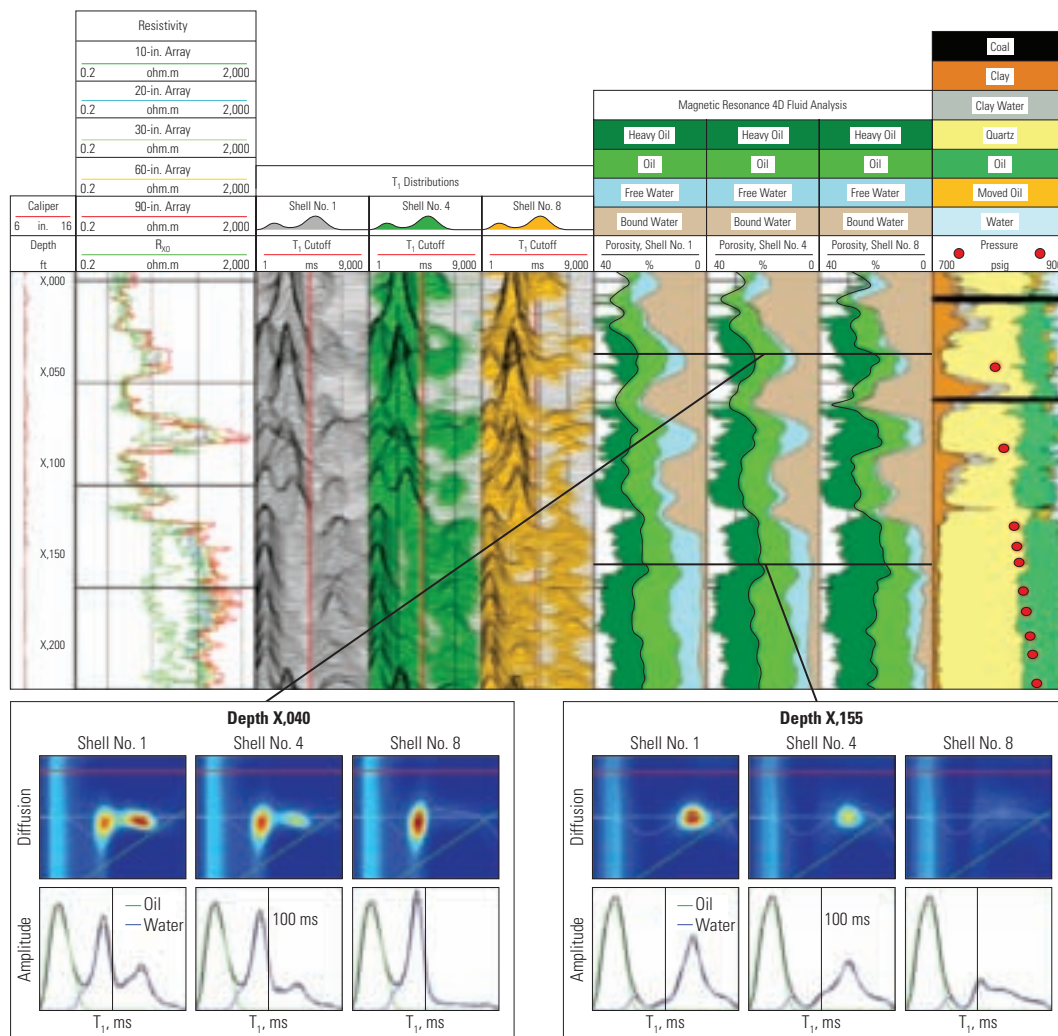
^ 4D NMR processing. Standard processing results in a lack of coherence between bound-fluid volumes measured by Shells No. 1, No. 4 and No. 8 (top, Track 1). The same is true for the free-fluid volumes (Track 3). Using 4D NMR processing, the bound-fluid volumes, which should remain constant across each DOI, are constrained and the porosity contributions are reassigned. The result is improved coherence for both the bound-fluid (Track 2) and free-fluid (Track 4) volumes. The fluid properties are affected by hole conditions from X,120 to X,135 ft (red shading) as evidenced by the increased porosity measured from the shallower shells (Tracks 5, 6, 8 and 9). Shell No. 8 (Tracks 7 and 10) senses from beyond the washout and provides more-accurate data. The  $D-T_1$  maps used for saturation computation for each shell demonstrate the effectiveness of 4D processing. The standard 2D NMR processing (bottom left panel) results in similar fluid volumes in Shells No. 1 and No. 4. Shell No. 8 has less bound fluid, but all three shells should have equivalent volumes because bound fluid should not change with DOI. The 4D NMR processing (bottom right panel) constrains the fluid volume to be the same below 30 ms. Reapportioning the porosity to account for the bound-fluid volume delivers a more-accurate measurement from the deepest shell. As a result, the 4.0-in. measurement furnishes fluid properties from a region less influenced by mud-filtrate invasion.

The independent measurements at various DOIs from the MR Scanner tool read deeper into the formation than the CMR tool. Not only has the MR Scanner tool overcome rugosity problems, it also has verified a condition—previously theorized from the CMR data—of partial- or whole-mud invasion effects on the bound-fluid volumes and permeability. These effects were especially noticeable in water zones. The mud solids did not appreciably alter NMR porosity, but the bound-fluid measurement was too high. As an input to the NMR permeability calculation, incorrect bound-fluid volume resulted in permeability outputs that were too low.

Deeper-reading NMR measurements overcome rugosity but have some trade-offs. Because the

formation signals from the deeper shells are weaker, noise has the potential to corrupt the processed data. Vertical resolution is degraded because data must be averaged or stacked over a longer interval to overcome the noise effects. The measurement from deeper shells is also acquired at longer echo spacings because of tool power limitations. The CMR tool uses 0.2-ms echo spacing so that in 10 ms it generates 50 pulses. This provides sufficient data to resolve some heavy oils such as those found in the Orinoco wells. However, the 1.0-ms echo spacing available from the MR Scanner tool's 4.0-in. shell provides only 10 pulses and echoes in an equivalent time frame. The result is a decrease in signal-to-noise ratio because there are fewer echoes to work with.

One solution to this dilemma comes in the form of four-dimensional (4D) NMR processing in which DOI is the fourth dimension.<sup>15</sup> This processing simultaneously inverts the NMR data within the portion of the relaxation-time distribution that should be common for all DOIs. For the Orinoco wells, the time interval to allow the oil signal to decay is always below 10 ms. The bad-hole and whole-mud effects begin after 20 ms. Imposing a common solution on each shell for the first 10 ms forces the deeper-reading 4.0-in. shell measurement to be equivalent to the higher-resolution 1.5-in. shell reading in this common-data area. The result is improved coherence between the shells and more-accurate readings from the deeper shell (above). This is



▲ The big picture in heavy oil. The  $D$ - $T_1$  maps from X,155 ft show bound-fluid and heavy-oil signals in the Shell No. 1 plot (*bottom right*). The free-water signal above 100 ms decreases progressively from shallow to deeper DOIs. The fluid analysis (*top*, Tracks 5 through 7) shows a steady decrease in free water from Shell No. 1 to Shell No. 8. The interpretation is that the source of the water signal is the mud filtrate, which displaced heavy but movable oil in the reservoir; the water signal would remain constant if filtrate were displacing formation water. For the zone from X,020 to X,050 ft, the interpretation is more difficult. The resistivity is lower (Track 1), and there is a water signal at each DOI.  $D$ - $T_1$  maps from X,040 ft (*bottom left*) provide fluid information. Because the water signal from filtrate invasion is present in Shells No. 1 and No. 4 but disappears in Shell No. 8, the interpretation is that filtrate displaced heavy oil that cannot be measured by the NMR tool. The strong water signal present in all three shells is from irreducible water, so the zone should produce water-free oil.

valid for borehole-rugosity and thick-mudcake effects, but heavy oil impacts the NMR measurements even when the borehole is in good condition.

Because heavy oils have short relaxation times and rapidly decaying signals, NMR tools invariably fail to measure all the heavy oil. This is true even with the shortest echo spacings currently available from downhole tools. Sequences with longer echo spacings miss even more of the heavy oil. The MR Scanner tool's deeper shell measurements have longer echo spacings than those of the shallower shells. Consequently, the volume of heavy oil that is measured by the tool decreases with DOI. The oil volumes will always be underestimated in these heavy-oil environments.

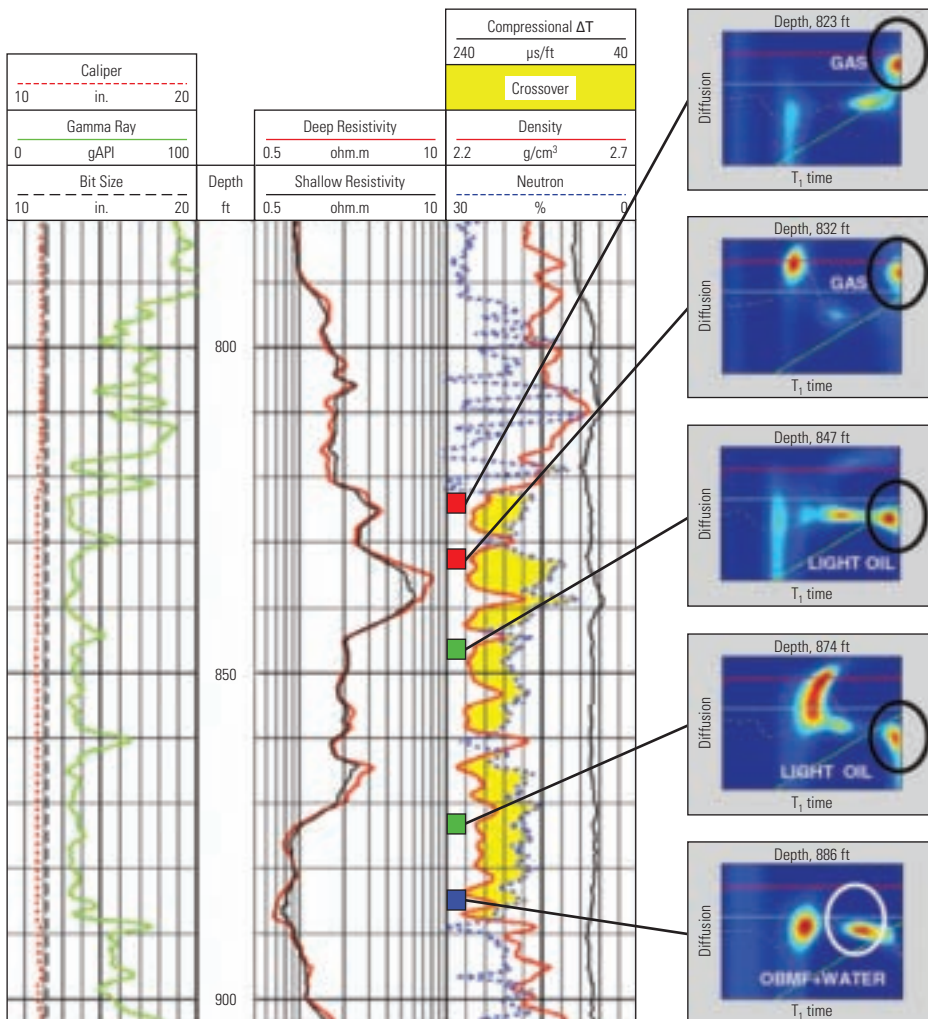
Despite this shortcoming, the effects of heavy oil on the measurement can still be used to understand the formation fluids. The measured NMR porosity decreases with DOI as a result of the missing heavy-oil signal. The measured volume of immovable bound water will not change with DOI. Invading filtrate will displace only movable water or movable hydrocarbon. Thus, the 4D inversion can be used in a manner similar to that used with hole rugosity, but the interpretation focus will be on the changes in free fluid and total porosity rather than borehole effects.

The 4D processing provides a marked improvement over that of conventional 3D inversion. The first 30 ms of the inversion are

constrained to be common across all three shells because it is assumed that bound fluid and the heavy-oil signals are stable in this time range at each DOI. This is in contrast to the processing used when borehole rugosity or whole-mud invasion is a problem; here, only the first 10 ms are constrained.

Well data show the free-water signal above 100 ms decreasing progressively from shallow to deeper shells (*above*). This leads to an interpretation that the source of the free-water

15. Heaton N, Bachman HN, Cao Minh C, Decoster E, LaVigne J, White J and Carmona R: "4D NMR—Applications of the Radial Dimension in Magnetic Resonance Logging," *Transactions of the SPWLA 48th Annual Logging Symposium*, Austin, Texas, June 3–5, 2007, paper P.



^ Determining fluid type. The resistivity and porosity data indicate a hydrocarbon interval from 822 to 872 ft. Mud logging during drilling suggested gas or condensate throughout the interval. *D-T<sub>1</sub>* maps from data acquired from the MR Scanner tool provide a different fluid analysis. The lowest interval (*bottom right*) contains connate water (white circle) and oil-base mud filtrate (OBMF). Successively higher points indicate a transition from light oil to gas (black circles). Based on interpretation of the NMR *D-T<sub>1</sub>* maps, this reservoir contains oil below 840 ft, rather than the expected condensate and gas.

signal is the mud filtrate and that it has displaced heavy oil in the reservoir, although the heavy oil is invisible to the MR Scanner tool. If the filtrate were displacing movable formation water, the water signal would be constant at deeper DOIs.

In a lower interval, the resistivity is high, exceeding 100 ohm.m, which leads interpreters to conclude that filtrate displaced oil. However, for the upper zones with lower resistivity values, the answer is less obvious. Lower resistivity values would suggest the presence of water rather than oil. NMR data provide the missing fluid information. Hydrocarbon in the form of heavy oil was displaced by the filtrate. Because the water signal from the filtrate is present in the 1.5-in. Shell No. 1 measurement but disappears

in the 4.0-in. Shell No. 8 measurement, these zones should produce water-free oil. A strong water signal remains in the *D-T<sub>1</sub>* maps at each DOI, but its source is irreducible bound water.<sup>16</sup>

Based on the answers provided by the 4D processing, the operator can confidently produce from the upper and lower sections with an expectation of little or no water production. Minimizing water production decreases upfront costs for surface equipment and, because water removal and disposal are not required, reduces costs over the life of the well.

#### Fluid Characterization

Fluid type directly affects the economic value of a field, and surface facility decisions depend on an accurate understanding of reservoir fluids.

However, many reservoirs contain more than one fluid type: Fluid composition may vary continuously or discontinuously across a reservoir interval. Fluid gradation is not always apparent with conventional well logs, and surprises can occur in both the early and later stages of production.

A North Sea exploration well was drilled to evaluate a reservoir that, based on an offset well, was believed to contain gas condensate.<sup>17</sup> Adjacent gas-handling infrastructure made the prospect an inviting target. Resistivity and density-neutron logs clearly indicated that this exploration well had a significant hydrocarbon deposit with approximately 48 feet [15 m] of net gas pay.

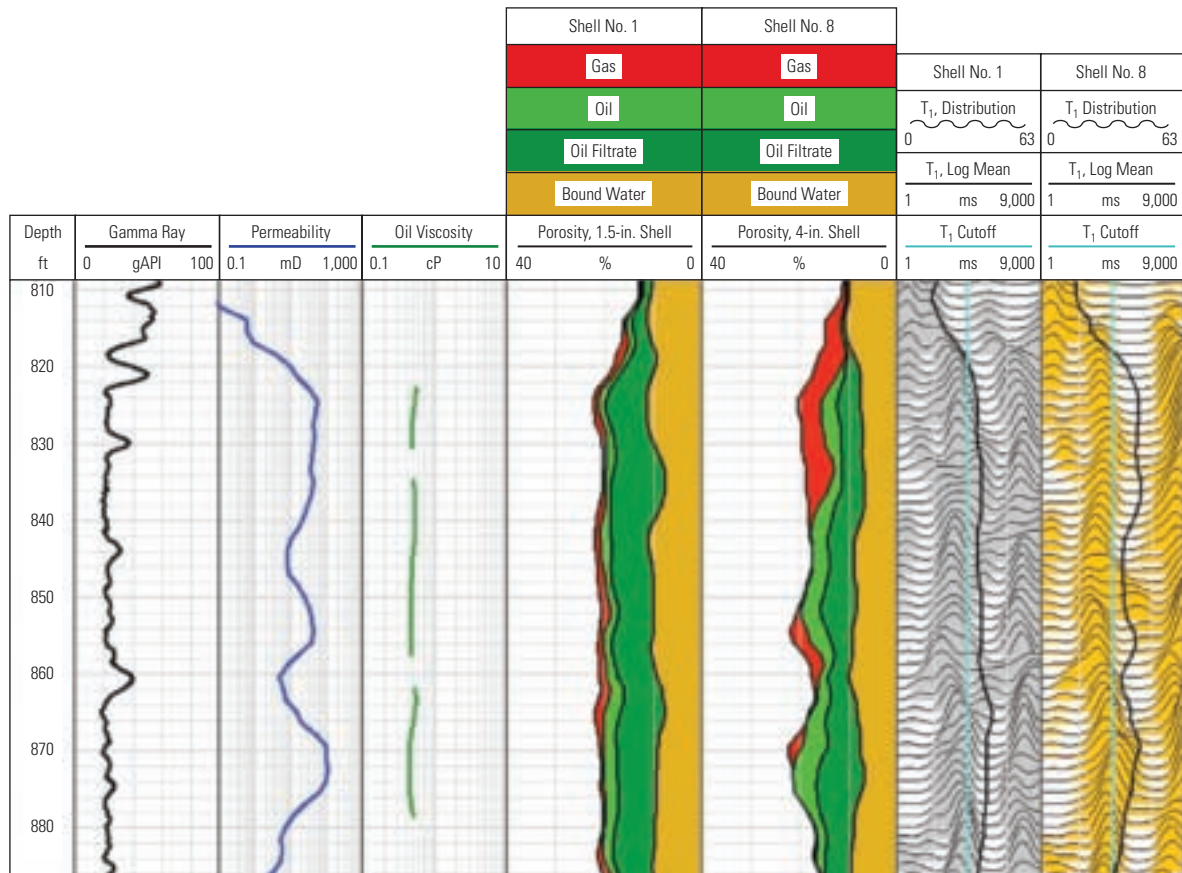
MR Scanner data were then acquired in a saturation-profiling mode. Diffusion and *T<sub>1</sub>* distributions, extracted from multiple wait time, variable echo-spacing sequences, were derived from the data. *T<sub>2</sub>* distributions were computed, but *T<sub>1</sub>* distributions proved better for analyzing the long relaxation times of the fluids in this reservoir.

Water and hydrocarbon saturations at 1.5-, 2.7- and 4.0-in. DOIs were computed from the data acquired in two separate logging passes. The *D-T<sub>1</sub>* maps at sequential depths were plotted and, although there is a clear gas signal in the upper part of the reservoir, the NMR interpretation concluded that a significant portion of the reservoir contained light oil—not condensate as originally anticipated (*left*).

Closer analysis of the data and the *D-T<sub>1</sub>* maps identified the gas/oil contact in the reservoir, as well as a stratigraphic feature assumed to be a vertical-permeability barrier. A 4D inversion enhanced the deeper shell measurement. The 1.5-in. shell data indicate a significant volume of oil-base mud filtrate (OBMF), but the deep shell output is less affected by the OBMF (*next page*).

The porosity and permeability derived from the MR Scanner data were immediately available to the client in the field. The acquired data were sent to a Schlumberger computing center for advanced processing. NMR fluid-property data were returned in time to assist in picking depths for pressure and sample points. Pressure plots indicated three different fluid gradients. Fluid samples confirmed the presence of gas in the upper interval and oil in the lower interval. Unfortunately, filtrate contamination prevented an accurate PVT analysis.

A two-stage drillstem test (DST), conducted after the well was completed, confirmed the presence of oil in the lower interval. The NMR data provided improved understanding of the complex nature of the reservoir fluids. The



^ Gas, oil and water. The permeability (Track 2) is consistent throughout the zone from 820 to 880 ft except for two areas with lower permeability at 845 and 860 ft. The viscosity (Track 3) indicates light oil, but its source is the OBM filtrate. The continuous fluid-saturation logs from Shell No. 1 (Track 4) and Shell No. 8 (Track 5) show fluid changes occur with deeper DOI. The well was drilled with oil-base mud, and OBMF (dark green shading) displaces native fluids. In contrast, the Shell No. 8 data show more native oil (light green) and gas (red). There is very little free water in the wet interval below 880 ft, perhaps because the free water has been flushed by OBMF. The well has more oil than originally anticipated, and consequently, less gas.

calculated volume of gas and condensate available for export from the reservoir was greatly reduced. The initial objective of the well, to develop and produce a gas reservoir, was modified along with the development plans for the field.

### Finding the Oil/Water Contact

Laminated sand-shale sequences, referred to as low-resistivity, low-contrast (LRLC) pay, are familiar to log analysts. They are often overlooked or improperly evaluated because the pay is not obvious using conventional logging tools. There are, however, high-resistivity, low-contrast (HRLC) reservoirs where everything looks like pay, and these provide an entirely different set of challenges. In HRLC reservoirs, resistivity changes caused by water-salinity variations and poor resistivity contrast between oil and water zones make determination of an oil/water contact (OWC) extremely difficult. Correct determination

of the OWC directly affects reserves calculations, completion designs and production decisions. Mistakes are costly, especially when high water cut reduces oil production while adding additional water-disposal costs.

Traditional evaluation techniques are based on resistivity contrasts between oil and saline formation water. Reservoirs containing fresh or brackish water may exhibit little or no resistivity contrast between the fluids. NMR fluid-saturation measurements are based on the volume of each fluid and are not dependent on water salinity. Thus, oil and water saturations derived from NMR data offer an ideal solution for evaluating HRLC reservoirs and determining fluid contacts.

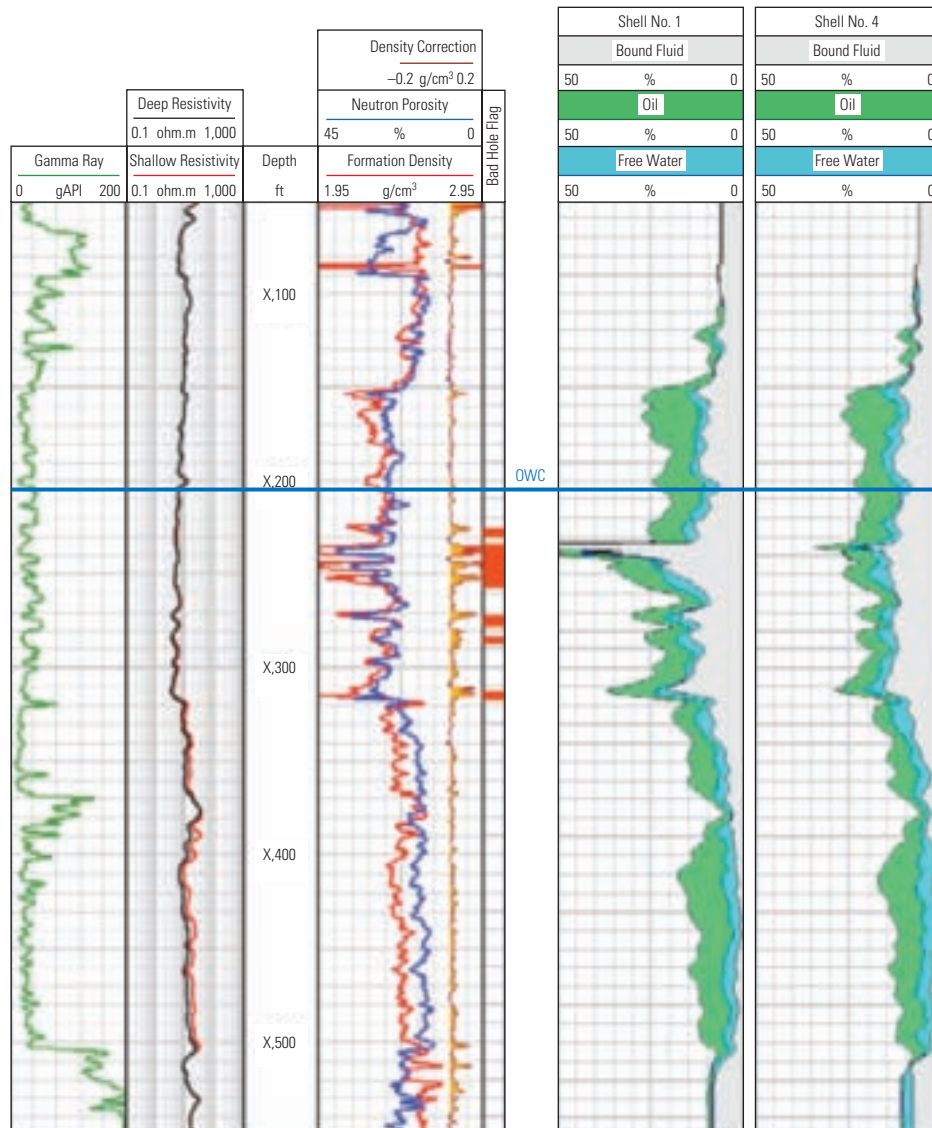
In a Middle East HRLC reservoir drilled with oil-base mud (OBM), determination of hydrocarbon saturation and the OWC was not possible using resistivity and porosity logs.<sup>18</sup> The method for finding the OWC was to use pressure

measurements from wireline-conveyed pressure-sampling tools to determine fluid gradients. The condition of the borehole often deteriorated during drilling, and pressures were difficult to obtain because of seal failures, yielding inconclusive results. Costly and time-consuming DSTs were then performed to pinpoint the contact.

Saudi Aramco discovered the subject field in the 1960s, but there had been no recent

16. Irreducible bound water in the reservoir remains in place during production, and hydrocarbons alone are produced.
17. White J and Samir M: "Continuous Characterization of Multiple Fluids in a North Sea Gas Condensate Reservoir by Integrating Downhole NMR with Downhole Sampling," *Transactions of the SPWLA 49th Annual Logging Symposium*, Edinburgh, Scotland, May 25-28, 2008, paper X.
18. Akkurt R, Ahmad NA, Behair AM, Rabaa AS, Cray SF and Thum S: "NMR Radial Saturation Profiling for Delineating Oil-Water Contact in a High-Resistivity Low-Contrast Formation Drilled with Oil-Based Mud," *Transactions of the SPWLA 49th Annual Logging Symposium*, Edinburgh, Scotland, May 25-28, 2008, paper Y.





^ OWC not found. Early logging attempts with the MR Scanner tool produced inconclusive results. In the well shown, the fluid saturations were computed using data from Shell No. 1 (Track 4) and Shell No. 4 (Track 5). Oil (green) is indicated from top to bottom of the interval, but it is OBMF, not native oil. Free water (blue) is also seen throughout the interval in data from both shells. A DST located the OWC at X,204 ft. From the NMR data, its location is not obvious. The presence of free water above the OWC was attributed to noise in the data and influenced the decision to take stationary measurements for future wells.

production. The company reactivated the field and then drilled evaluation wells to properly characterize the reservoir and determine locations for horizontal multilateral producing wells. In the first well logged with the MR Scanner tool, the tool was part of a logging suite that consisted of resistivity, density porosity, neutron porosity, acoustic and spectroscopy tools along with a formation pressure and sampling program.

In the past, conventional logging tools had been unable to identify the OWC. Fluid gradients from pressure data were not conclusive. NMR saturations were acquired using data from the

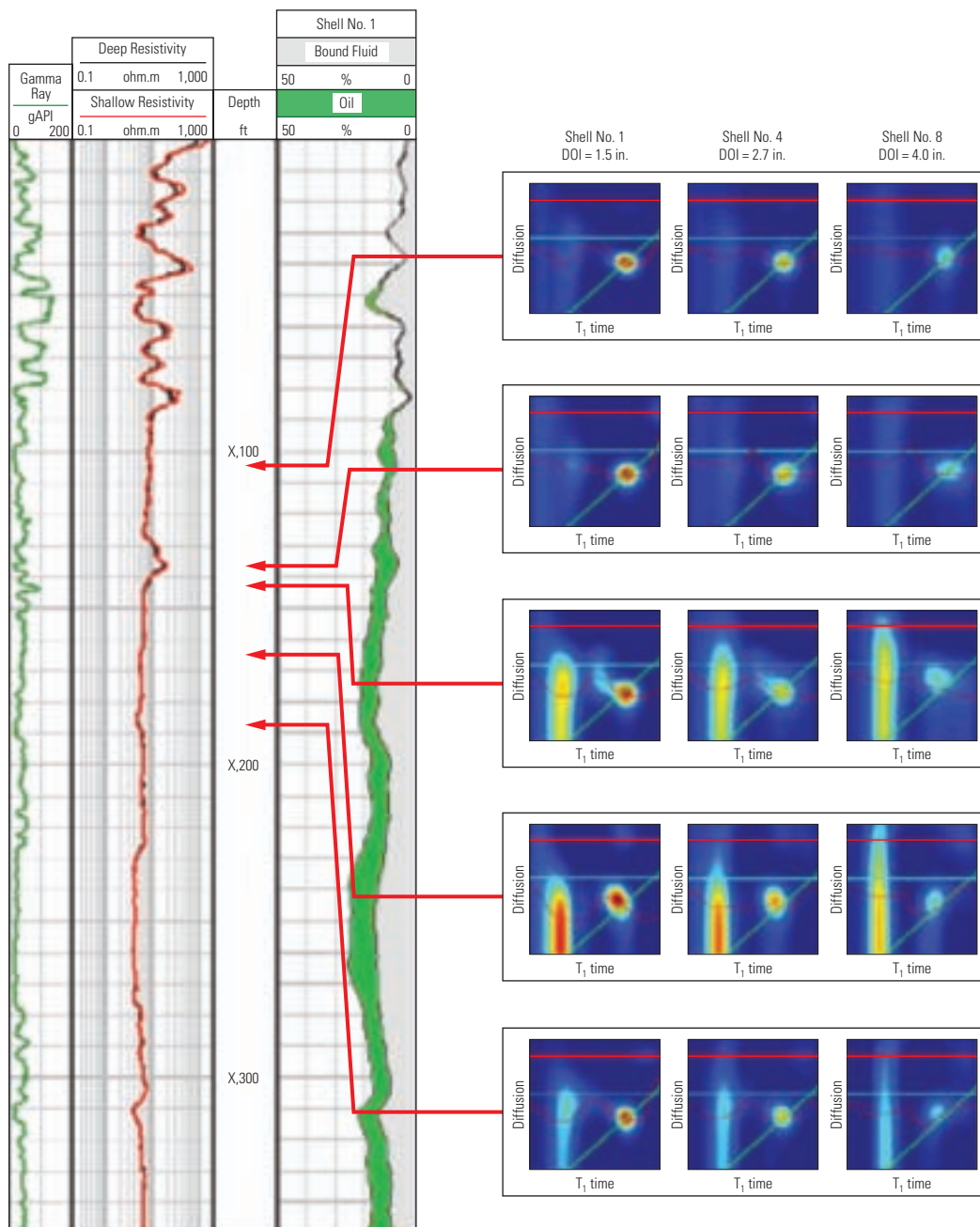
MR Scanner tool. However, the saturations indicated that the entire zone was pay, which was known to be incorrect based on production from offset wells.

The inability of the NMR tool to identify the OWC was attributed to less-than-optimal acquisition parameters for the challenging case of this HRLC pay. The reservoir contains low-viscosity light oil, and NMR experts concluded that the lack of success in locating the OWC resulted from using a wait time that was insufficient to fully polarize the native oil. A new acquisition sequence was created to address the underpolarization.

In the next well, the MR Scanner tool used this modified sequence, acquiring data from the

1.5-in. and 2.7-in. shells (above). The results again indicated pay throughout the interval. OBM filtrate had flushed out native water and oil throughout the interval. Upon closer inspection of the results, a subtle increase in the computed water volume was observed in the water leg from the 2.7-in. shell data compared with that computed from the 1.5-in. shell.

The presence of OBM filtrate explained the oil in the water leg. The 2 to 3% of free water seen in the known oil leg was not so easily explained. It was assumed that the signal-to-noise ratio was insufficient for accurate volumetric calculations and the increase in the computed water volume was due to noise.



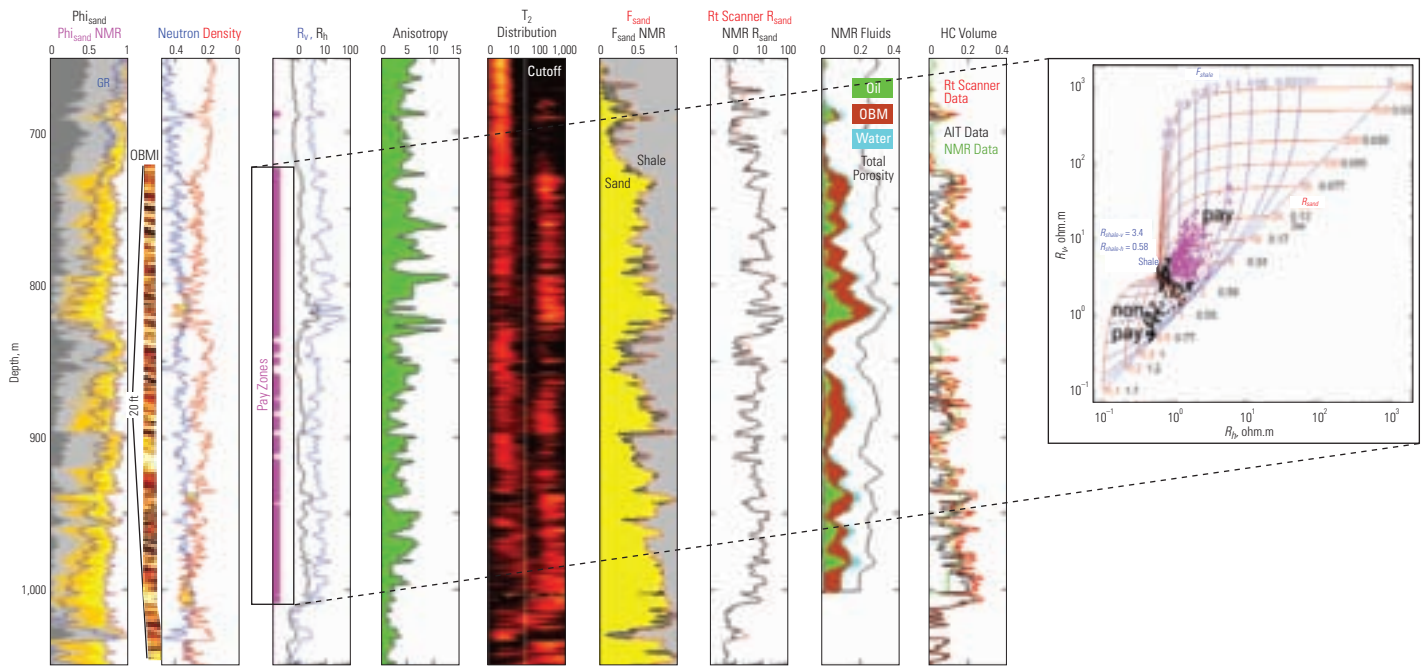
▲ Pinpointing OWC with station logs. After the inconclusive results from early attempts to use MR Scanner data to locate the OWC, stationary measurements were used. Station logs permit stacking of data to achieve higher signal-to-noise ratios. Continuous fluid analysis from Shell No. 1 (Track 2) shows oil throughout the interval, but the source is the OBM filtrate. A three-DOI sequence allows Shell No. 8 data to be acquired simultaneously with Shells No. 1 and 4. The deeper shell detects native oil when invasion is not too deep. The two top stations, at X,103 and X,138 ft, are in the oil leg and have a clear oil signature, with little or no water signal from all three shells. The three bottom stations, at X,142, X,165 and X,185 ft, are in the water leg, as evidenced by a strong free-water response. The absence of movable water in the upper two maps pinpoints the OWC at X,140 ft. Formation samples confirmed the interpretation.

In a third well, the petrophysicists acquired data from the 4.0-in. shell, and from the two shallower shells, using stationary measurements. Station data can be stacked to obtain a better signal-to-noise ratio. Continuous data were acquired from the 1.5- and 2.7-in. shells. As before, the data from the two shallower shells looked similar, with a strong OBM filtrate

response. However, the stationary data from the 4.0-in. shell clearly indicated free water in the water leg. Surprisingly, looking an additional 1.3 in. [3.3 cm] into the formation made a big difference in identifying the OWC.

Given the success of using the stationary measurements from the deep shell, which clarified the fluid distributions and explained vertical trends in the reservoir fluids, three-shell

measurements were added to the standard logging program. A first-of-its-kind triple-shell activation sequence to simultaneously measure all three DOIs in stationary and continuous logging modes was also introduced. This replaced multiple passes and multiple stations previously required to obtain three DOIs (above). Today, MR Scanner data play a critical role in the evaluation



Integration of data in an anisotropic reservoir. A laminated reservoir is inferred from the OBMI image data (between Tracks 1 and 2). Processing began by calculating sand volumes (Track 1) from density-neutron and NMR data. Horizontal,  $R_h$ , and vertical,  $R_v$ , resistivities (Track 3), derived from the Rt Scanner tool, were used to compute the electrical anisotropy (Track 4, green). The shales and the laminated sand-shale intervals exhibit anisotropy. The  $T_2$  distributions from the NMR data (Track 5) indicate bimodal fluid distributions in the intervals where sand is present, but not in the shales. Free fluid is to the right of the  $T_2$  cutoff, and clay-bound fluid associated with the shale is to the left. Sand fractions were computed with inputs from both the NMR and the Rt Scanner data (Track 6). Sand resistivity (Track 7) was calculated from Rt Scanner data using intervals

with free fluid as defined by the MR Scanner tool. The NMR fluid saturations indicate oil, water and OBM filtrate (Track 8). Hydrocarbon (HC) volumes are displayed for comparison (Track 9). They are computed from NMR data (green), the Rt Scanner data (red) and Archie's water saturation equation using traditional AIT array induction imager tool outputs derived from the Rt Scanner data (black). Traditional Archie saturation underestimated the HC volume throughout the interval, significantly reducing the calculated net pay and hydrocarbon in place. Finally, the petrophysicist identified the laminated pay intervals using a modified Klein plot (*inset*) that incorporates Rt Scanner data, NMR data and high-resolution porosity measurements. Productive zones are highlighted on the log (Track 3, magenta).

program of the field, and use of three-shell data has been adopted as a best practice.

However, one limitation of the MR Scanner tool's ability to identify fluid type came to light during the analysis of the data from this field. NMR fluid properties, acquired from just a few inches into the formation, can be of little help in identifying fluid contacts when invasion exceeds the 4.0-in. DOI of Shell No. 8. In these cases, MDT modular formation dynamics tester fluid gradients and DSTs are required to provide the needed information.

### Resolution Solution

The trend in log interpretation and tool design has been toward resolving and measuring increasingly thinner beds. This is critical in the interpretation

of anisotropic, laminated sand-shale sequences. However, it is not possible to resolve extremely thin laminations with NMR tools because of the general requirement to stack successive measurements to achieve an adequate signal-to-noise ratio. With a CMR tool, the smallest aperture window is a 6-in. [15.2-cm] station measurement. The MR Scanner tool's main-antenna measurement window is 18 in. Recent developments demonstrate that even at this lower resolution, NMR data are still useful in analyzing and interpreting laminated sequences. NMR data provide complementary petrophysical measurements of the reservoir fluid properties that resistivity and porosity measurements cannot.<sup>19</sup>

There are three general methods used to analyze thin-bed reservoirs using well logs.<sup>20</sup>

Traditionally, imaging logs are used to characterize the laminations, separating sand from shale. Other, lower-resolution data are then deconvolved using the higher-resolution image data. These outputs are used in Archie's equation to compute water saturation. One drawback to this method is that imaging tools make very shallow readings and thus rely on good borehole conditions to acquire quality data. Furthermore, full quantitative analysis, using deconvolution techniques, is often inconclusive, and fluid properties and type are rarely quantifiable.

In a second method, NMR data quantify the type and volume of fluids in a reservoir section. But since it is not possible to resolve thin beds with NMR tools, this method lumps the fluids together and differentiates bound fluid from free fluid.

19. Cao Minh C and Sundararaman P: "NMR Petrophysics in Thin Sand/Shale Laminations," paper SPE 102435, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, September 24–27, 2006. Cao Minh C, Joao I, Clavaud J-B and Sundararaman P: "Formation Evaluation in Thin Sand/Shale Laminations," paper SPE 109848, presented at the SPE Annual Technical Conference and Exhibition, Anaheim, California, USA, November 11–14, 2007.

20. Claverie M, Azam H, Leech R and Van Dort G: "A Comparison of Laminated Sand Analysis Methods—Resistivity Anisotropy and Enhanced Log Resolution from Borehole Image," presented at the Petroleum Geology Conference and Exhibition (PGCE), Kuala Lumpur, November 27–28, 2006.

21. Anderson B, Barber T, Leveridge R, Bastia R, Saxena KR, Tyagi AK, Clavaud J-B, Coffin B, Das M, Hayden R, Klimentos T, Cao Minh C and Williams S: "Triaxial Induction—A New Angle for an Old Measurement," *Oilfield Review* 20, no. 2 (Summer 2008): 64–84.

22. For more on the use of modified Klein plots: Cao Minh C, Clavaud J-B, Sundararaman P, Froment S, Caroli E, Billon O, Davis G and Fairbairn R: "Graphical Analysis of Laminated Sand-Shale Formations in the Presence of Anisotropic Shales," *Petrophysics* 49, no. 5 (October 2008): 395–405.

23. Hürlimann MD, Freed DE, Zielinski LJ, Song YQ, Leu G, Straley C, Cao Minh C and Boyd A: "Hydrocarbon Composition from NMR Diffusion and Relaxation Data," *Transactions of the SPWLA 49th Annual Logging Symposium*, Edinburgh, Scotland, May 25–28, 2008, paper U.

Within laminated sands, bound fluid is associated with shale laminations, and aggregate free-fluid volume is associated with sand laminations. Diffusion data can provide fluid properties when sufficient quantities are available in the reservoir rocks. Although the depth of investigation is deeper than that of imaging tools, NMR measurements are still quite shallow.

A recently introduced third method of evaluating laminated sand-shale sequences incorporates high-resolution porosity information and induction tool data, such as those from the Rt Scanner triaxial induction service.<sup>21</sup> This tool measures horizontal,  $R_h$ , and vertical,  $R_v$ , resistivities. In laminated sands, the hydrocarbon-bearing sand laminations exhibit electrical anisotropy, indicated by a high  $R_v/R_h$  ratio, whereas water-bearing sand-shale sequences have low ratios. Reservoir evaluation based on the electrical anisotropy alone is not sufficient to prove the presence of hydrocarbon. Anisotropic shales exhibit high  $R_v/R_h$  ratios even in the absence of hydrocarbon-bearing sand layers because of formation compaction.

In an even newer technique, MR Scanner fluid measurements are combined with the Rt Scanner  $R_v/R_h$  method to provide critical information for properly analyzing complex sand-shale reservoirs. This method yields sand fraction (net-to-gross), sand porosity, sand resistivity and hydrocarbon saturation. The key to maximizing the value of the information is integration of the data from the various sources.

This complementary integration technique was recently demonstrated in a west Africa reservoir. Characterized as having a thin sand-shale sequence, the well in this case study was evaluated with MR Scanner data, Rt Scanner information and high-resolution porosity data from formation density and neutron logs.

Once thin beds with hydrocarbon potential had been identified from image data, the petrophysicist followed an established workflow to interpret them:

- Compute the sand fraction,  $F_{sand}$ , from the porosity data.
- Derive sand resistivity,  $R_{sand}$ , from  $R_v$  and  $R_h$  data.
- Compute an NMR  $F_{sand}$  from the  $T_2$  distributions.
- Derive a new  $R_{sand}$ .
- Compute the porosity of the sand layers,  $\Phi_{sand}$ , from both the density-neutron data and the NMR  $T_2$  distributions.
- Compare water saturations computed with inputs from the NMR data with those derived from the Rt Scanner and high-resolution porosity data.

With this workflow, the data analysis for this well began with identifying laminations from the image log of the OBMI oil-base microimager (previous page).  $R_v$  values are greater than  $R_h$  values, indicating electrical anisotropy. But, the  $R_v/R_h$  ratio is high in clean shales as well as in laminated sand-shale sections.

Shales have only bound fluids and thus a unimodal  $T_2$  distribution. Sand-shale sequences exhibit a bimodal distribution, indicative of movable fluids in sand laminations. Thus, the sand fraction,  $F_{sand}$ , can be derived from the free-fluid portion of the NMR  $T_2$  data. This value is then compared with the  $F_{sand}$  value derived from the density-neutron data.  $R_{sand}$  values are computed from the triaxial induction tool data for both  $F_{sand}$  inputs. The NMR fluid analysis of data from the 2.7-in. shell indicates native oil and OBM filtrate.

Three analysis methods for water saturation are used to calculate the hydrocarbon volume: Archie's water saturation equation, the  $R_v$  and  $R_h$  method using triaxial induction tool data, and NMR fluid saturations.  $R_v$  and  $R_h$  crossplots are presented using a Schlumberger modified Klein plot technique.<sup>22</sup> The selected points from the crossplot are transposed on the log, identifying quality reservoir intervals. Anisotropic shales plot in the nonpay region and may be ignored. With this technique, the log analyst quickly assesses the reservoir and identifies potential pay zones.

This integrated approach resulted in an 80% increase in calculated net-to-gross values as compared with classical resistivity-porosity methods. An increase of 18 net hydrocarbon feet [5.5 m] is derived from the NMR-based saturations, and there is an increase of 15 net feet [4.6 m] using the triaxial induction technique without NMR data. The conclusion from the log evaluation is that NMR data enhance the calculation for hydrocarbons in place, while corroborating the results of triaxial induction-based laminated-sand analysis. The technique offers the petrophysicist the ability to identify quality reservoir intervals and eliminate nonproductive anisotropic shale intervals from evaluation.

### Mapping the Future of Magnetic Resonance

Magnetic resonance logging has transcended its niche market status and attained a high level of acceptability within the petrophysical community. It will never supplant resistivity and nuclear porosity measurements; nor should it. NMR data offer the oil and gas industry an alternative source for certain measurements, including porosity and fluid saturations, yet there are limitations inherent in the physics—as there are in all petrophysical measurements.

New enhancements to the software for making 2D maps of reservoir fluids create static snapshots that can then be added to 2D logs. In addition, the software has the capability to present saturations and fluid properties in a video format, allowing visualization of the changes that take place laterally along the wellbore and horizontally into the formation.

Laboratory-based NMR fluid measurements have been and will continue to be transferred to the downhole environment. Obtaining the properties of sampled fluids while tools are still downhole offers the closest approximation to in situ measurements available. An NMR oil classification system exists based on molecular properties, and applying that classification to downhole fluids will aid in proper reservoir development.<sup>23</sup>

But one of the unique aspects of NMR measurements is that they offer the only technique that can see and distinguish different fluids in situ, without flowing them. Even downhole samples may not provide true fluid properties because of changes to the fluids during flow. Sampled fluids do not reflect the true distribution of fluids in the reservoir, only those that are mobile. As NMR techniques are applied, and fluid variations within reservoirs are identified, the complicated nature of oil and gas production is better understood. With reservoir understanding come informed production practices, greater efficiencies and higher recovery rates.

Viable options exist for future development. Researchers continue to develop NMR-based carbonate answers. Deeper measurements are a goal, but tools to acquire them are years away. Although there may never be an NMR measurement from the virgin reservoir, fluid properties from LWD tools offer a glimpse into the reservoir fluids unaffected by mud filtrate. Such a solution would overcome the problem identified in the Saudi Aramco HRLC wells. Other challenges await further research and development.

It took 30 years to develop a workable magnetic resonance tool for downhole environments. NMR measurements have continued to evolve along with the tools used to acquire the data. The most recent developments put a colorful visualization technique in the hands of the petrophysicist. The art and science of NMR applications have been combined to provide an alternative to static 2D logs of the past. These new dimensions in NMR logging have ushered in a powerful tool for reservoir analysis. But the best may be yet to come. —TS