A New Method of Fluid Identification from Nuclear Magnetic Resonance Logs*

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Abstract

The Mississippian Formation that is productive through much of Kansas and Oklahoma is a difficult, altered lime reservoir with a significant amount of secondary porosity. Production generally is from horizontal wellbores and has a very high water cut. Decisions regarding the best interval of the reservoir for completion in vertical wells and for horizontal drilling in horizontal wells is very problematic due to the rapid alteration and compartmentalization of the reservoir. Like many carbonate reservoirs around the world, water segments may be above, below, or in between hydrocarbon traps. In many cases, the water portions of the reservoir and the hydrocarbon portion have the same resistivity. Any technique that can accurately characterize the reservoir for fluid type provides tremendous value in drilling and completing these types of wells.

Thus, Nuclear Magnetic Resonance (NMR) logs were added to the evaluation program to obtain this type of evaluation. Fluid type, independent of resistivity, can sometimes be accurately determined using the polarization (T_1) measurement. This measurement responds to the type of molecule being manipulated. In many reservoirs, the fluid type can be accurately forecast using only this measurement.

Reservoirs like the Mississippian present a situation that cannot be simply solved. The T_1 measurement can be distorted by the rapid alteration of the reservoir rock. These alterations may be primary porosity changes from deposition or compaction. They could also be related to secondary porosity development after deposition.

This paper presents an evolving technique that incorporates both the T_1 measurement and the relaxation (T_2) measurement to accurately determine the type of molecules in the reservoir pore space. Numerous examples of characterization will be presented. When possible, production results will also be presented. Comparison of the results forecast versus those actually achieved, indicate a positive future for this new approach to fluid type, independent of any other logging or coring result.

Introduction

The Mississippian Formation in Kansas and Oklahoma has developed into one of the most prolific oil producing reservoirs in the Mid-Continent area of the United States. The reservoir has long been identified as a potential reservoir with some production being established as early as the 1930s. The areas that were successful during early development were areas where significant quantities of oil and gas could be established and produced without large quantities of water. There were also areas of the reservoir that produced with high water cuts. These areas were generally uneconomic and operators abandoned these portions of the reservoir.

Another complication in this reservoir is that there are barriers within segments of the formation. Several different reservoir portions may be identified with completely separate reservoir packages. In some cases, each of these compartments has a gas cap, an oil section, and a water section. These repeated packages are separated by boundary conditions that are difficult to identify on logs, but are consistent enough to create sealing contrasts.

Several factors combined to change the economics of these reservoirs. The primary factor was a large increase in the price of oil. This changed the economics of oil wells in general. High water cut wells could now be produced economically even when a portion of revenue was expended in the disposal of the produced water.

The second major economic factor step change was the increased efficiency of horizontal drilling. This process allowed much more of the reservoir to be exposed to the wellbore and a concomitant increase in produced fluid rates. If the water cut of the produced fluids could be maintained at a low enough level, significant quantities of hydrocarbons could be recovered in an economically feasible environment.

All of these conditions demanded a well-planned evaluation and completion scheme to maximize production. Identification and targeting of more hydrocarbon-rich portions of the reservoir inevitably resulted in more economic completions. These sections could be directly targeted in vertical wells.

Horizontal wells could be drilled in the oil-productive portions of the reservoir and the completion could achieve higher oil cuts than if the well were drilled randomly. The ideas to achieve these better hydrocarbon cuts were simple in principle, but much more difficult in actual practice.

Any of these conditions required an evaluation technique that could discriminate and, if possible, isolate the hydrocarbon portions of the reservoir from the water portions. This proved extremely difficult since traditional log analysis measurements and analyses could not provide these solutions. Rapid textural changes within the reservoir made it impossible to accurately characterize porosity. In addition, density and neutron responses did not always indicate the same solutions as each responded to the appropriate stimulus.

This rapid vertical and horizontal alteration of the reservoir also presented problems for characterization from resistivity logs. With large volumes of surface area exposed in the altered portions of the reservoir, conductivity measurements were short-circuited through the formation and produced very low resistivity measurements. Comparison with results from drill stem tests indicated that even with a resistivity below 1 Ohm, water-free production could be achieved. However, the rapid alteration of the reservoir precluded the ability to consistently apply any derived conclusion.

Nuclear Magnetic Resonance (NMR) logs were added to the logging suite in an attempt to understand and characterize the fluid type. Since the responses of various fluids have different responses to imposed magnetic field variations, the hope was that water, oil, and gas could all be discriminated and defined by this technology.

Proposed Approach

NMR logs are unique in reservoir analysis since they are the only logging tool that only inspects the pore space of the rock. The magnetic manipulation of molecules only affects the fluids and the fluids are present in all of the available pore space. When all of the measurements are added together, the result is porosity. NMR logging measurements are insensitive to protons in the rock matrix, so conventional techniques that require knowledge of shale volumes, or other parameters, are not required to understand the volume of available pore space with NMR logging. Since this is a direct measurement of the total pore space, the implication is that the NMR tool is measuring total and effective porosity.

Figure 1 shows the results of NMR measurements on pore spaces and fluids. As described previously, the measurements made by the magnetic resonance tool have responses only from the fluids. The tool is capable of making two separate measurements that are each useful for different purposes.

The left half of Figure 1 is a characterization of the time, in seconds, required for molecules to respond to a strong magnetic field. This is termed ‘magnetization’ in this plot. Another name commonly used for this characteristic is ‘polarization’. These are the same thing and are also labeled as T_1.

The time of each molecule response is driven by the type of molecule that is being influenced. Clay-bound water responds almost instantaneously, moveable water at a later time, and hydrocarbons event later than that.

This difference in response time gives rise to a technique to determine fluid type based simply on the T_1 response time. The analysis is based on the idea that only certain molecules respond after a certain time. Inspection of the T_1 section of Figure 1 gives some credence to this technique. Almost all of the water response is concluded prior to about 3 seconds and only hydrocarbons continue to magnetize very late in the time window.

Figure 2 is a log example of how the data was presented when using T_1 as a fluid type indicator. Track 3 is the T_1 data presented from 0.5 ms out to 5000 ms. There is a dotted black line inscribed as ‘oil line’ that is drawn at 2000 ms, along with a red dotted line at 5000 ms. The implication here is that molecules that achieve resonance later than 5 seconds are gas molecules, molecules that stabilize between 2 and 5 seconds are oil molecules, and anything earlier in time than that are water molecules of some type.

A visual inspection of this data may indeed indicate the type of molecule involved in the measurement, but a volumetric description is not possible. In track 5, the computer totals all of the data measured later than 5 seconds; the white shading with red crosses is all of the data measured later than 2 seconds but earlier than 5. In this log, the presence of hydrocarbon is easily identified in the upper portion of the logs and the signal decreases toward the bottom of the log.

This seemed to be a very powerful technique for identifying the presence and type of hydrocarbon. This was very superior to conventional techniques using resistivity and porosity since the measurement is affected only by the molecules and not by environmental effects that can distort responses from conventional logging tools. This idea was applied with very good results in a variety of different reservoirs. These reservoirs ranged from thinly bedded, tight sandstone to highly permeable and well-sorted sandstone. They also included, tight, unaltered carbonate-to-fracture dominated carbonate systems and even into heavily altered systems with intense fracturing and vugs.

However, there is a clearly identified problem with this technique. Looking at Figure 1 again and comparing the responses in relaxation time, or T_2, there is a difference in fluid time responses due to variations in pore size. In simpler terms, fluid molecules that reside in larger pores do not respond in exactly the same way as molecules that reside in smaller pores. This means that a simple time discriminator for fluid type will not always work directly, especially in reservoirs that have drastic differences in pore size. This can happen any time secondary porosity is present from any source. Variation sources are typically fractures in sandstones or fractures and vugs in carbonates.

Figure 3 is an excellent example of this problem with fluid typing. The log section has fairly consistent resistivity through the entire section. It is very low resistivity; a standard Archie calculation would deliver a water saturation result that would indicate water production. Inspection of the T_1 response in track 3 shows a very distinct change at 4810 feet. Above that point, the apparent fluid type is gas and oil. Below that depth, the response is in the water window.

The porosity description provided by the T_2 in track 1 exhibits a large change in both total porosity and in the distribution, or quantity, of pore measurements within each time window. This implies a coarsening up sequence. However, this cannot be a direct conclusion because the apparent fluid type has changed from water in the lower part of the log to hydrocarbon in the upper portion. This change could be partially related to alterations in the reservoir or simply related to changes in fluid type. Without some additional data or analysis technique, this enigma is difficult or impossible to resolve.

Therefore, a proposal was made to acquire the total NMR signal and analyze this as a total system. This allows consideration of the entire response to the NMR measurement. After the acquisition, the total signal is plotted and polarization (T_1) and relaxation (T_2) are extracted from the plotted signal. These measurements are no longer discrete data sets. This allows consideration of the effect of each distortion based on pore size and on fluid type.

Figure 4 is an example of how this technique is applied. The full spectrum of the NMR measurement is included in the plot in the upper left segment. T_1 is extracted from this spectrum on the right and T_2 is extracted under the plot. The analysis of fluid type is in the tabular listing in the lower right portion of the figure. In this listing the fluids are identified as water, oil, and gas. There is a volume of each component of fluid type presented as porosity units and a saturation volume of each of the fluids as a percentage of total volume.

The time distributions collected in each of the windows provide a similar answer to the polarization and relaxation presentations of data in the past. However, the solutions of fluid type are no longer limited by the discrete time cutoffs required by other analysis techniques. For the first time, consideration of time effects in T_1 and T_2 created by fluid differences may be characterized for their effect on fluid type conclusions.

In this case, the plot is for a single depth of 4572.40 feet. All of the extracted T_1 response is earlier than 1000 ms. This would indicate water and the tabular listing of fluid type results confirms that there is no oil and no gas at this depth. There is approximately 21% porosity measured with water in it and virtually no contribution to porosity from oil and gas. The saturation analysis is 100% water with no oil or gas.

This 2D analysis of this portion of the reservoir allows condemnation of this portion. Completion dollars expended here would have no return. No matter how large the treatment, as long as the reservoir maintains this composition and fluid type, nothing will improve performance. This is a valuable addition to any data set. The ability to identify ineffective expenditure of resources allows those resources to be applied to more productive portions of the reservoir.

Figure 5 is another point analysis of the total NMR signal in a different section. Visual inspection of the spectrum compared to the previous example shows much digression in the signal. The strength and location of the signal now arrives in many different areas of the spectrum. T_1 and T_2 extractions both contain much more character than before.

The relaxation signal is fairly consistent in time. This indicates a well-sorted reservoir. This good sorting provides greater permeability per porosity unit. In addition, most of the well-sorted arrivals are late in time, which further enhances the permeability calculation.

The magnetization signal has a diverse set of arrivals; some very early in time, and some very late in time. The late time signal is easily characterized as gas. The portion that is problematic is the very large late time signal. As observed in Figure 1, this time response could be migrated later in time due to the large pore sizes described by the relaxation response. Consideration needs to be given to the raw magnetization response due to the pore-size effect.

The analysis at this depth of 3560.20 feet is about 10 porosity units of water, approximately 1.5 pu of oil, and an apparent 0.5 pu of gas. At first glance, this would seem to be a large volume of water and another portion where water would dominate production.

However, consideration must be given to the effect of invasion on this measurement. The NMR measurement is 4 inches deep into the formation. During the drilling process, drilling fluid will invade much of this space. When drilling with water-based mud, if only water is in the formation, water will be 100% of the signal from this analysis. If hydrocarbons are in the formation, many of the hydrocarbon molecules will be displaced by the invading drilling fluid. Analysis of this invasion diameter is key to understanding the fluid type of the reservoir.

The proposed approach of this paper is to use the spectrum analysis of the NMR signal to discriminate fluid types in the reservoir. Identification of reservoir segments of gas on top of oil and on top of water will be presented. This identification will rely completely on the NMR response in the reservoir.

Analysis

Figure 6 is an example of one of the difficult reservoirs for fluid type analysis. The conventional logs are presented in this figure. Density and neutron porosity are presented in track 6 with density as a solid line and neutron as a dashed line. Crossplot porosity from 4802 feet to 4852 feet is in the 15-17% range. There is good apparent crossover in this section while the P_e is around 3. This would indicate a siliceous reservoir with clay inclusions, but with the presence of gas.

Resistivity is low. The interval 4803 feet to 4823 feet has a resistivity of 2-3 ohms. The rest of the zone has resistivity in the 1.5-2 ohm range. Conventional Archie calculation of the fluids indicates a very high water cut.

The NMR distribution of relaxation indicates the presence of large pores. From the previous discussion, this will cause the time arrival of the magnetization to be migrated later in time. This may be a situation where indicated hydrocarbon may indeed be water because of this distortion.

The T_1 signal in track 3 has very little apparent character. The signal is all concentrated at a time that cannot be clearly identified as oil, gas, or water. The expectation in drilling this well was that oil production could be achieved, but the raw assessment of the signal indicates that completion would also produce significant amounts of water.

Figure 7 is analysis of this difficult log section using the NMR results from full spectrum signal. The plot on the left is for the interval 4803 feet to 4813 feet. In the log in Figure 6, this is the interval that has a slight migration to the right in the T_1 signal in track 3. It is a very subtle shift and difficult to identify, but there is certainly some type of transition effect here so the decision was made to partition at this point.

The results of the analysis are presented in the tabular listing. The porosity measured in this 10-foot interval is composed of 11% water, 2.5% oil, and an apparent 3.2% gas. The fluid type is partly hydrocarbon of some type. The water component is drilling fluid, connate water, or a mixture of both.

The plot on the right is analysis of the full NMR spectrum for the interval 4822 feet to 4848 feet. In this interval, the T_1 measurement in track 3 of Figure 6 appears to be two-thirds to the left of the hydrocarbon line and one-third to the right, or in the hydrocarbon window. Based on this data, direct conclusion of fluid type in this interval would be impossible.

However, in Figure 7 the result is clearly defined in the tabular listing of the NMR results from dissection of the spectrum plot. Porosity by volume is composed of 15.5% water, 1.3% oil, and 3.7% gas. Saturation is 76% water, 6% oil, and 18% gas. The fluid is now 24% hydrocarbon but a very different mixture. The gas saturation has remained constant, but the oil has dropped from 15% to 6%. Clearly, there is some change in the reservoir fluid that is causing this drop in saturation.

Thinking like a reservoir engineer helps to bring some closure to this dilemma. In a conventional reservoir, gas would be on top, oil next, and water on the bottom. In this reservoir, the gas is constant through the section. Therefore, one of two things is happening; the formation could be hydrocarbon from top-to-bottom and the oil could be displaced by invading drilling fluid or the gas may be consistent throughout the formation and entrained in the other fluids.

Figure 6 helps provide some insight into this reservoir. The relaxation measurement in track 2 shows a very consistent measurement of time from top to bottom. This implies that the formation has approximately the same character through the formation with the same relative permeability through the entire section. This should provide consistent invasion in all portions of the reservoir.

Since the invasion must be the same from top to bottom in this log section, the differences observed by the spectrum analysis of fluids must be attributed to fluid type changes and not pore size variations or fluid invasion artifacts. The conclusion then is inescapable that the top section of the reservoir contains oil and gas and the bottom section contains water and gas with some residual oil.

This conclusion was tested in this well when tubing-conveyed perforating systems were used to perforate the interval from 4804 feet to 4814 feet. This well was placed on production at 80 BBL oil per day with no water from these perforations.

Conclusions

NMR logs provide unique perspectives into reservoirs and the potential fluid types found there. Formations that are indecipherable from conventional logs may have great clarity supplied by using this technology that operates on a different principle than conventional logs.

Analysis of the magnetization (T_1) signal without consideration of complicating factors may lead to erroneous conclusions about fluid type. The signal may have some distortion due to variations in pore size or changes in fluid type. Either of these, taken alone, may be characterized by this single input, but when both are present, accurate assessment is difficult. Incorrect fluid type determination may result in poor completion results and economic failure.

Full spectrum analysis of NMR results provides clarity in these cases. By recording the full spectrum of the signal and extracting magnetization and relaxation from the results, the effects of all variations occurring in the reservoir can be considered. Accurate porosity from each fluid type can be determined and then fluid saturation within the interval of investigation is accurate and precise.

These fluid type determinations must be considered from both reservoir and geology standpoints to understand compartmentalization of the reservoir and migration of the fluids. Fluid migration must be considered in relation to invading drilling fluid to get a clear understanding of reservoir productivity.

The reservoirs in this paper were light oil and this technique works very well in that condition. Additional work to evaluate the effectiveness of this technique in heavy oil is in progress.

This powerful tool now allows correct determination of reservoir intervals that should be completed and separation from water incursions. Completion decisions can be made to best target hydrocarbon zones, even those that are not apparent from other logging approaches and tools. This technique has been applied with excellent results in both carbonate and sandstone reservoirs.

Selected References

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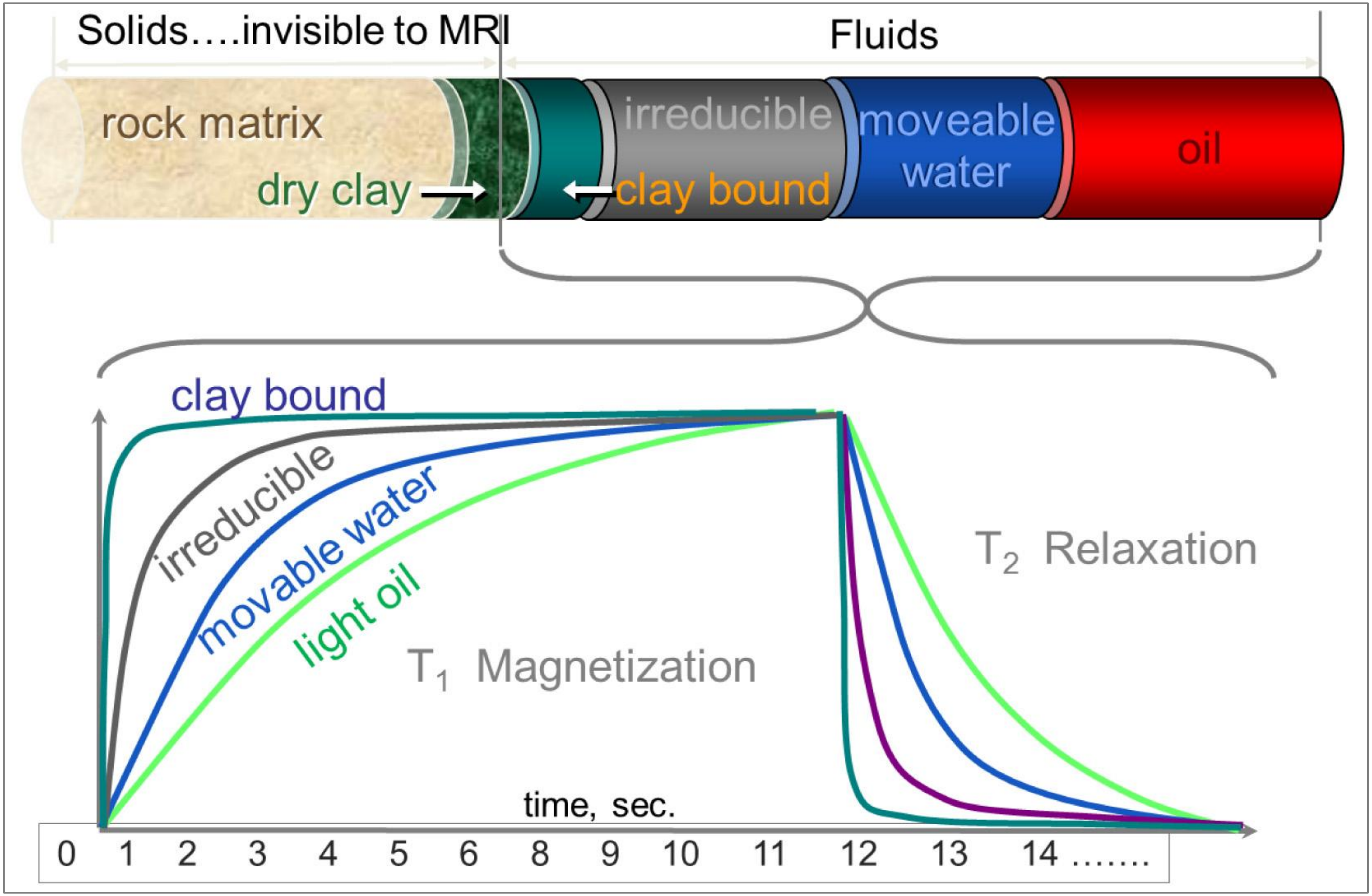

Figure 1. Measurement Characteristics of NMR Logs.

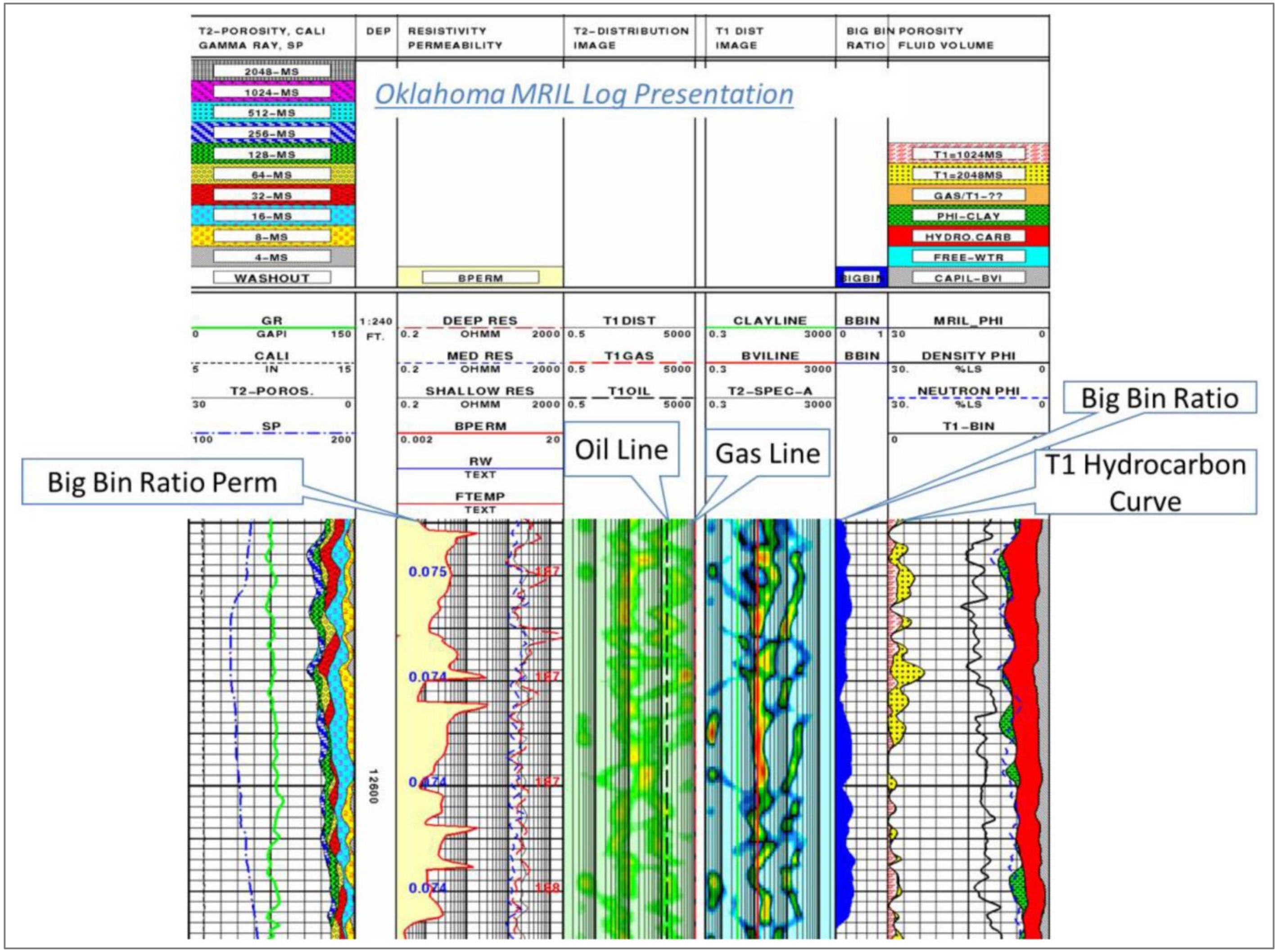

Figure 2. Fluid Type Analysis from Direct Magnetization (T_1) Inspection of Data.

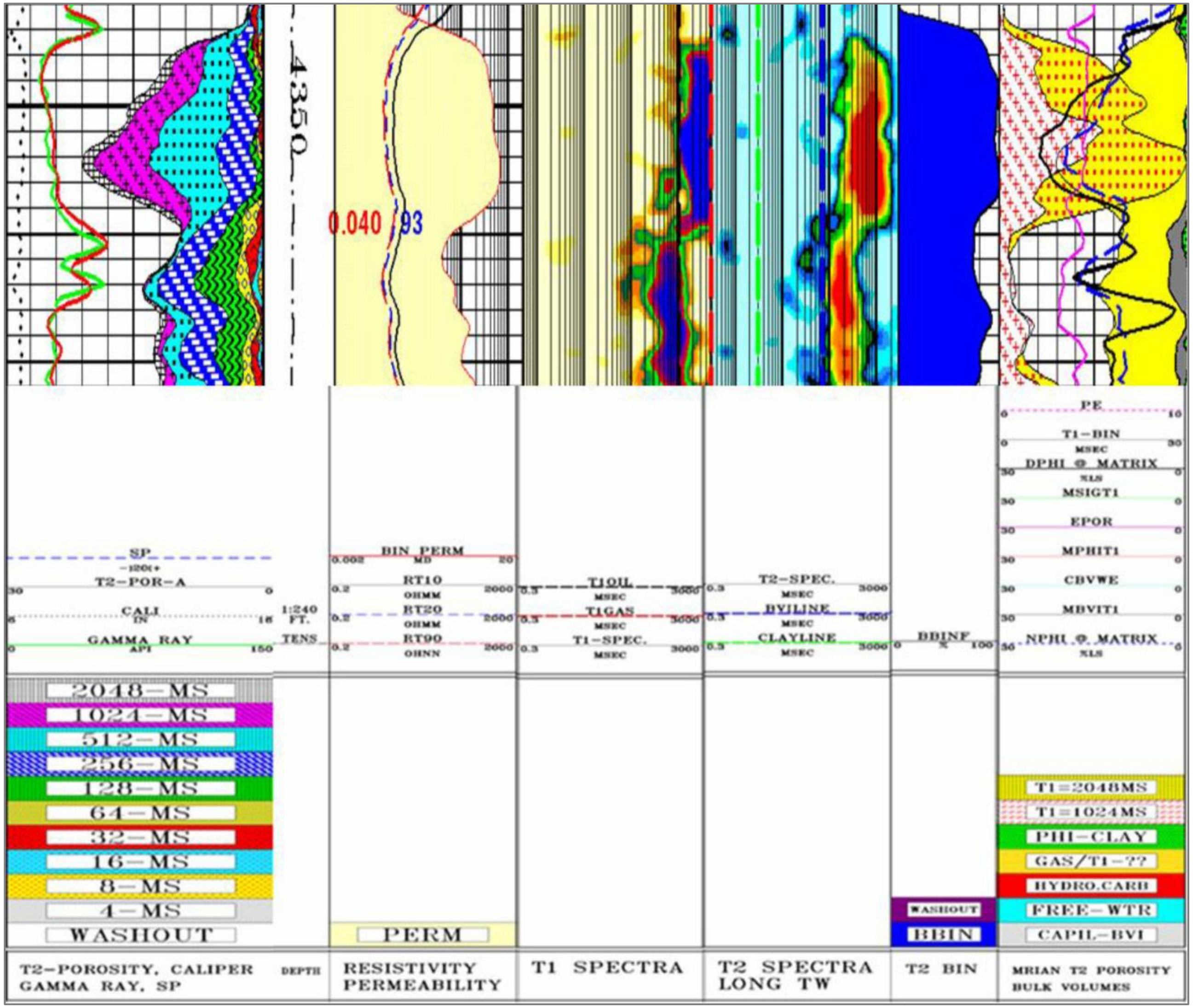

Figure 3. Apparent Pore Size Alteration with Change in Fluid Type.

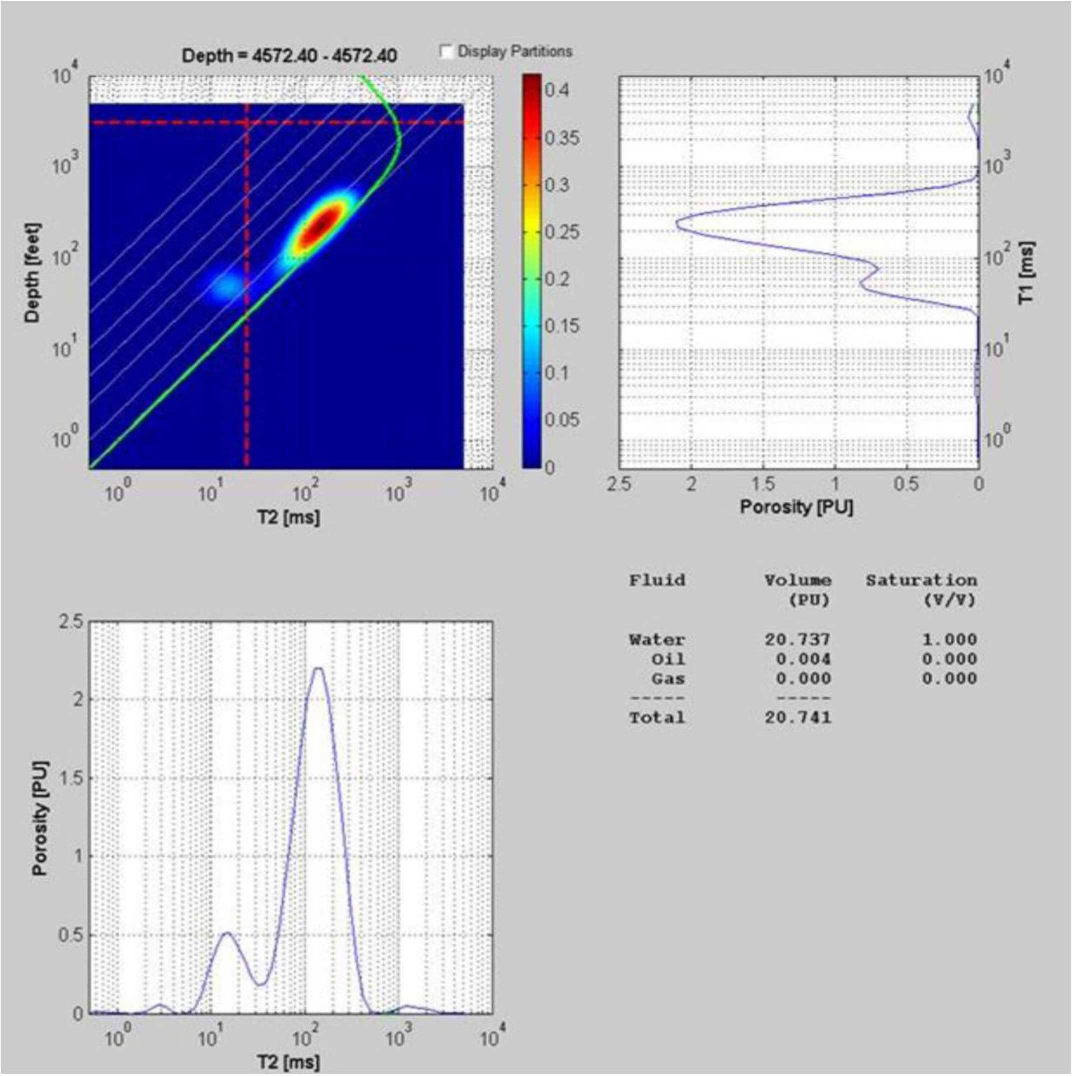

Figure 4. Spectrum Analysis of NMR Signal.

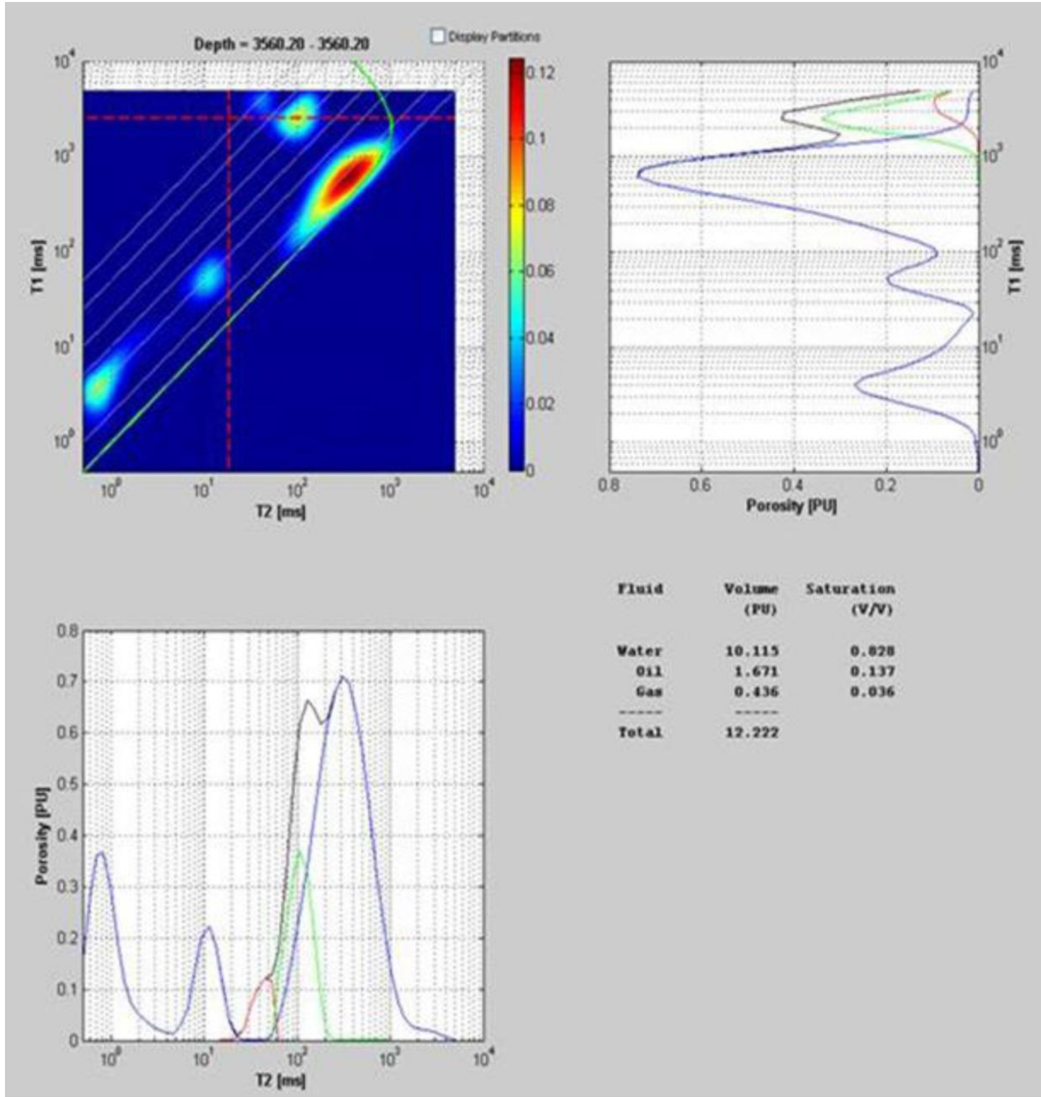

Figure 5. Spectrum Analysis of NMR Signal in Hydrocarbon Section.

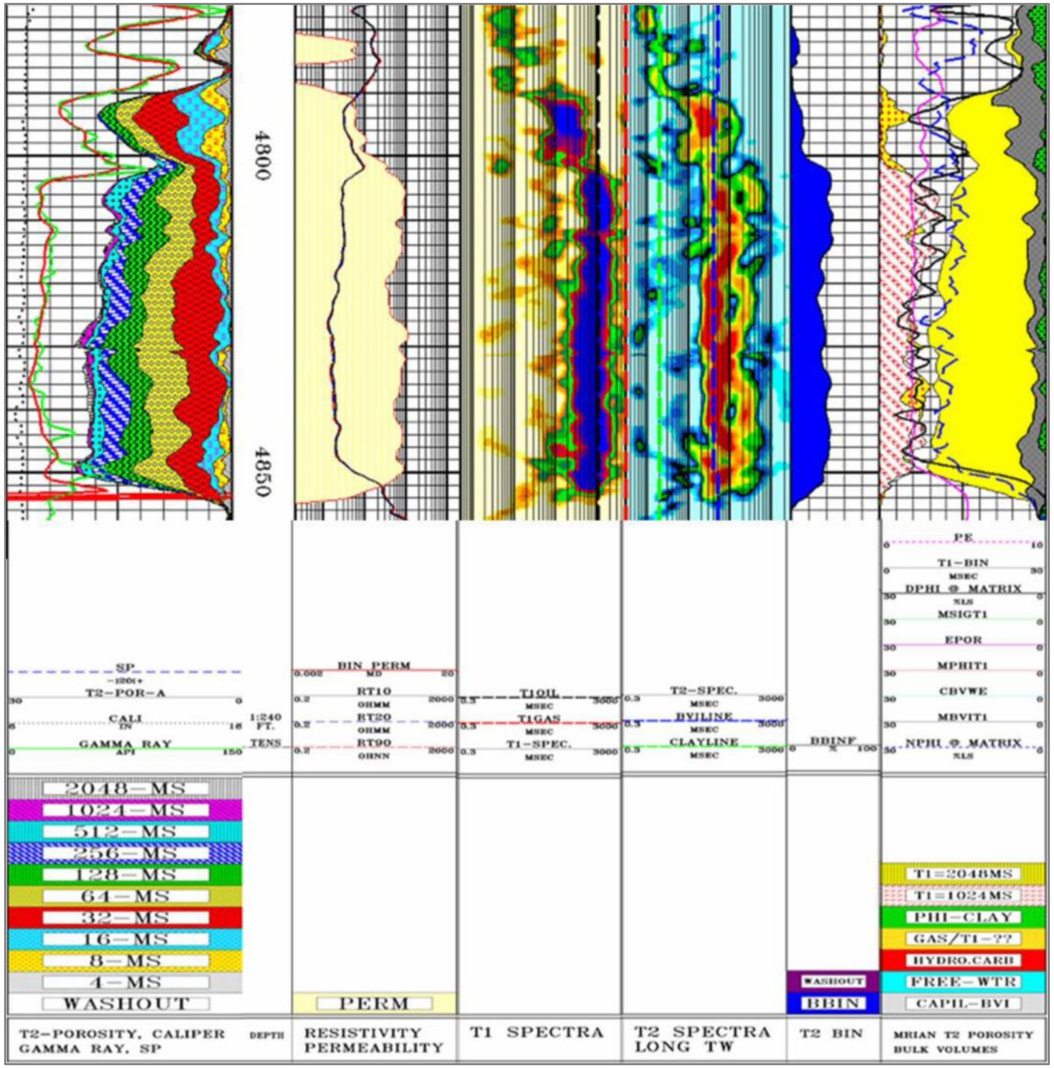

Figure 6. NMR Log Section with Potential Fluid Type Changes.

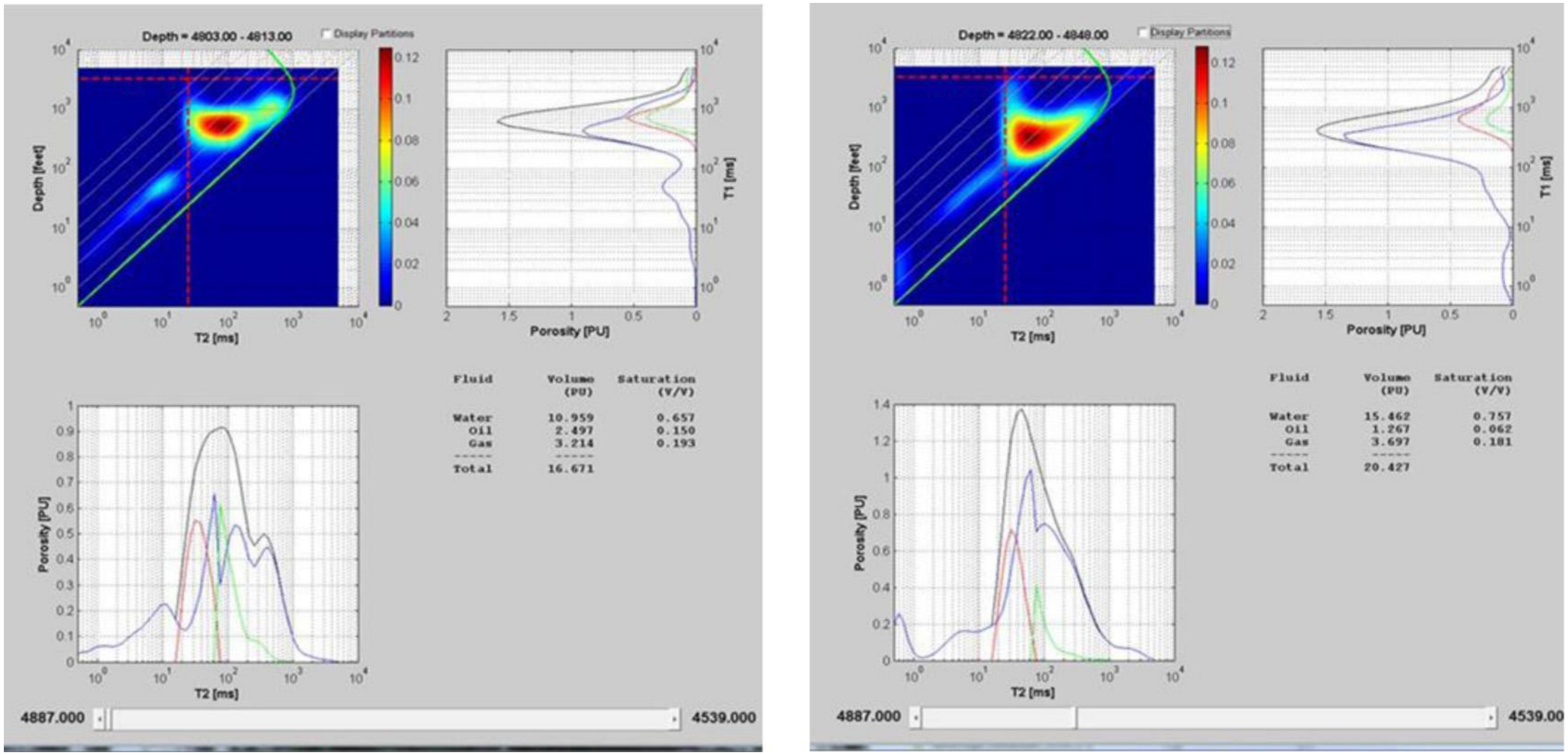

Figure 7. Full Spectrum Analysis of NMR Results in Difficult Fluid Conditions.