Resistivity not Required: Fluid Identification From Nuclear Magnetic Resonance Logs*

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Abstract

The Mississippian Formation, which is productive through much of Kansas and Oklahoma, is a difficult, altered lime reservoir with a significant amount of secondary porosity. Production generally has a very high water cut. The reservoir exhibits much secondary porosity development in the form of vugs and fractures. Water-productive portions of the reservoir may be separated from hydrocarbons by reservoir stratification and segmentation or through direct contact. Both the water and the hydrocarbon portions of the reservoir often have the same resistivity measurements. Archie calculations of water saturation are not always helpful. Closely monitoring cuttings from drilling and performing drill-stem tests at shows is the most common evaluation technique. This quickly becomes very costly. Thus, nuclear magnetic-resonance (NMR) logs were added to the evaluation program to evaluate fluid type. Polarization (T_1) measurements from NMR have been the most applied approach to this difficult fluid identification. Because this measurement responds to the type of molecule being manipulated, in simple 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 presence of secondary porosity in the form of fractures or vugs can distort the T_1 measurement. These alterations may be primary porosity changes from deposition or compaction or secondary porosity development after deposition. Either condition could distort the T_1 signal and would definitely affect the resistivity measurement. This paper presents a 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. A comparison of the production forecast vs. production actually achieved indicate a powerful new capability to establish fluid type, independent of any other logging or coring result.

Objectives/Scope

The Mississippian Formation is one of the most productive oil and gas reservoirs in the Kansas and Oklahoma region of the United States. This formation extends through almost all of northern Oklahoma and most of Kansas and is considered to be a difficult lime reservoir, having very dense and low porosity without alteration. It does exhibit a significant amount of secondary porosity. Production depends on the contribution of these secondary porosity features to increase permeability. This secondary porosity development takes the form of vugs and fractures.

Production generally has a very high water cut, but the water-bearing portion of the reservoir is not easily distinguished from the hydrocarbon-bearing parts. The water-productive portions of the reservoir may be separated from hydrocarbons by reservoir stratification and segmentation, or the phases may be in direct contact with each other.

The water and hydrocarbon portions of the reservoir are often not easily distinguished because they have the same resistivity measurements. Because of this, Archie calculations of water saturation are not always helpful and are sometimes outright misleading.

Intense monitoring of cuttings by wellsite geologists has become a preferred method to segregate different reservoir portions and attempt to reduce water production. When potential hydrocarbons are identified by the wellsite geologist, performing drillstem tests of these hydrocarbon-show intervals is a common evaluation technique. The exact interval where hydrocarbon shows are identified cannot always be isolated in the DST interval. Sometimes, multiple tests are run in a single wellbore. This can quickly become very costly.

Methods, Procedures, Process

Magnetic resonance (MR) logs were added to the evaluation program as a means to evaluate the fluid type. Polarization (T_1) measurements from MR have been the most applied approach to this difficult fluid identification. Because this measurement responds to the type of molecule being manipulated, in simple reservoirs, the fluid type can be accurately forecast using only this measurement.

Reservoirs like the Mississippian present a situation that cannot easily be solved. The presence of secondary porosity in the form of fractures or vugs can alter the T_1 measurement. These alterations may be primary porosity changes from deposition or compaction or secondary porosity development after deposition. Either condition could alter the T_1 signal and would definitely affect the resistivity measurement.

This paper presents a 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. A comparison of the production forecast vs. production actually achieved indicates a powerful new capability to establish fluid type, independent of any other logging or coring result.

Magnetic resonance (MR) logs were added to logging programs to assist in direct identification of the quantity and quality of these alterations. An MR measurement is the only logging measurement that measures the area of void space available and quantifies it. This is a direct measurement of effective porosity. The rock portion of the reservoir cannot be investigated by MR devices, only the fluid components.

Figure 1 is a representation of the measurements made by an MR device (Marchel et al., 2009). A very strong magnetic field is introduced in close proximity to the formation. All of the fluids that have polarity, which are in the open spaces in the reservoir, attempt to respond to this field by aligning with the field. This is termed polarization time, or T_1.

Each fluid type responds at a different rate, but with sufficient exposure to this field, a statistically accurate sum of the responses from each of the fluid types can be obtained. To make a complete polarization measurement, a significant amount of time is required. Figure 1 shows that the time required is 12 seconds. The sum of all of the T_1 measurements is the quantity of total porosity in the reservoir. This measured effective porosity includes the volume of all of the secondary porosity events. The contribution of secondary porosity in any form can now be accurately measured and included in effective porosity reporting.

The large difference in polarization time by different fluids led to a theory that fluid type could be inferred from this T_1 time. Figure 2 is a log where this application has been put into practice. Inspection of the polarization track, or the yellow track in the center of the log, shows an abrupt shift to a later time at a depth of 4,360 ft.

Resistivity above and below that shift are almost exactly the same, so this does not assist in fluid identification. The shift in T_1 makes clear that a drastic fluid change has occurred at this depth. This data indicated a sharp oil/water contact. The zone was tested above 4,360 ft and produced water free.

In a general sense, this relationship held true, but Figure 1 also shows that the T_1 response created by different fluid responses could also be affected by the size of the pore where the molecules in question were measured. In reservoir situations, where the demarcation between oil and water was not as distinctly established, inaccurate assessments of fluid type are possible. In fact, even in this log, the argument could have been made that this abrupt change in T_1 was created by the change in relaxation observed in Track 1.

Reference again to Figure 2 shows that above the 4,360-ft depth, the T_2 pore sizes indicated are in the 256-ms time range and later. Below that depth, the T_2 times are less consistent, but much earlier in time. It is possible that this event could only be an alteration in the form of secondary porosity within the reservoir. In this particular case, the well was tested, but the confusion that may arise in many difficult interpretation situations is easily discerned in this log.

Figure 3 is another log example of the interpretation of polarization to establish fluid type. T_1 is accepted at face value, and the fluids in the section are described as increasing in hydrocarbon volume higher in the section. In a reservoir without a distinct contact, this is a possible accurate assessment.

Examination of the T_2 components shows that the presence of large pores is also increasing from bottom to top through the reservoir. It is not possible to determine the effect of increasing pore sizes on the polarization measurement using this analysis technique. The resistivity does not help in a solution; the recorded value is higher in the top part of this reservoir than at the bottom.

Another useful example of the problem with this direct T_1 technique is exhibited in Figure 4. In this log, both the T_1 and the T_2 responses are highly consistent throughout the entire section. There is little to no movement in either response that would indicate a difference in fluid vertically through the section.

The only possible clue to fluid change is in the resistivity. The top few feet have a higher reading of 4 ohms, compared to 2 ohms lower in the section, but concordant with this rise in resistivity is a decrease in porosity. An apparent water-saturation calculation shows that this resistivity change is consistent with the porosity change. Archie calculations of either resistivity would imply 100% water in this section.

In each of the logs presented, there can be some data that would make the interpretation of the fluid type difficult. Direct T_1 is not always a reliable estimate; the effect of T_2 changes in the interval can change the signal response so that clear indications of hydrocarbon and water are not always possible. Similarly, resistivity does not provide additional useful details in an attempt to understand the reservoir.

A new, innovative technique that incorporates all signals captured by a magnetic resonance (MR) tool may be useful. This technique is called two-dimensional fluid characterization, or 2 DFC. This system captures the total signal available and plots it. The plot view is shown in Figure 5 (Smith et al., 2014)**.**

Figure 5 illustrates a point plot at the depth of 4,572.4 ft. The magnetic signal is plotted by intensity indicated by the color bar to the right of the plot. The location of the plotted signal is analyzed to determine the fluid type identified. In this case, all of the porosity measured is from water signal, as shown in the volume tabulation on the plot. This equates to a 100% water zone, as shown in the saturation column.

Multiple fluid types can be characterized in this same way. Figure 6 is an example of a 2 DFC plot with multiple fluid characterizations. A comparison of this plot to Figure 5 shows how the different fluid types are characterized. The indications of signal are now scattered across the plot. Each separate indication provides information about T_1 and T_2 as they are extracted as one dimensional projections on the right and bottom of the plot, respectively.

These data stacks are evaluated to show the volume of the total extracted from each fluid type. In this case, 10.115 porosity units (PU) are characterized from water, 1.671 pu from oil, and 0.436 pu from gas. This provides a percentage of each fluid identified as 82.8% water, 13.7% oil, and 3.6% gas.

The MR tool always investigates pore spaces and fluids in the invaded zone, so any measurement will be dominated by invasion, if there is any. The tool cannot segregate drilling fluid in fresh mud from connate water, as it only identifies water. Understanding the composition of fluids in the reservoir requires a characterization of the fluids from 2 DFC methods, then a comparison of changes in fluid identified within a specific reservoir group to project production fluid type. The reservoir section that included the interval shown in Figure 6 was tested and produced oil with some gas and no water. In this instance, the 83% water characterized by 2 DFC was completely drilling-introduced water.

This powerful technique can be applied to characterize fluid type and infer production in the difficult formation conditions in the Mississippian Formation.

Results, Observations

The most difficult log condition identified in the previous images is in Figure 4. From conventional log analysis and from the MR data, there is not any clear distinction of any fluids in the reservoir. All indications are that this is a wet section of the reservoir with some hydrocarbon. There appears to be so much water in the reservoir that any hydrocarbon component would only be a fraction of the total production. Water injection and lift costs would make this reservoir uneconomic.

A 2 DFC analysis was applied to this reservoir. Figure 7 is the plot for the interval from 4,822 to 4,848 ft; the interval is marked with red lines at the top and bottom of the log on the right. In this log, the interval is shown with two-dimensional fluid characterization of the MR data. As expected, there is a great deal of water present, but the volume that is connate is unknown.

The volumes of fluids observed are 15.462 pu of water, 1.267 pu of oil, and 3.697 pu of gas. This yields a fluid composition of 75.7% water, 6.2% oil, and 18.2% gas. Without reference to anything else in the reservoir, the numbers do not clearly indicate fluid type.

The relative understanding of this reservoir is established by comparison to another segment of this reservoir. Figure 8 is the 2 DFC analysis of the reservoir depth from 4,803 to 4,813 ft. This interval is again marked on the log at the right of the plot. Visual inspection does not provide an appreciation for the differences between the lower part of the reservoir and this section. There is a significantly larger portion of the log that shows oil, or green shading. The gas, or red-shaded segment of the reservoir, appears to be about the same, but there is still a very large component of water present in this section. The unknown, which cannot be visually discerned, is what the increased volume of hydrocarbon may be when compared to the lower section.

The fluid in this 10-ft interval is characterized as 10.595 pu from water, 2.497 pu from oil, and 3.214 pu from gas. The components from this information are 65.7% water, 15.0% oil, and 19.3% gas. The visual expectation of constant gas through the reservoir is confirmed, with essentially 18% gas in the lower reservoir compared to 19% in the upper part.

The two large changes are in water and oil. The water component decreased from 76% to 66%, while the oil component increased from 6% to 15%. Because the only change observed was a decrease in water and an increase in oil, the conclusion was drawn that this increase was due to a concentration of oil in the upper segment of the reservoir. This 10-ft interval was tested by perforations only, with no acid or stimulation, and flowed oil and gas with no water.

The oil volume that was identified in the lower portion of the reservoir was characterized as residual oil that could not produce. This residual oil volume will also be present in the upper part of the formation, but current production technology will not allow for the production of this hydrocarbon.

This comparison of fluid characterization and deduction of residual oil volumes was then usefully applied to other wells in this Mississippian reservoir. In general, the residual oil volume was between 5 and 9%. When the characterized oil component exceeded 13% in these conditions, water-free production could be established.

This powerful technique has allowed for valid fluid-production characterization in this difficult reservoir, where the economics can be dramatically impacted by water production and disposal. Operators are now able to understand the portions of the reservoir to be targeted in order to maximize the value of the asset.

Conclusions

The Mississippian Formation in the central USA is very difficult to interpret from standard open-hole logs. Resistivity can be completely unchanged from the top to the bottom of the reservoir, even with significant changes in porosity and fluid composition.

Magnetic resonance logs (MR) added to the logging program provided additional understanding of the reservoir. Initially, the evaluation of polarization, or T_1, was used as a direct indicator of fluid type. In some cases, this was successful, but there were many reservoir conditions that confused the response of this single component measurement. Anytime secondary porosity conditions were encountered, the change in the size of the pore spaces could alter the prediction of the fluid type.

A two-dimensional fluid characterization (2 DFC) analysis of the total magnetic signal provides an analysis that allows for the consideration of pore-size changes in the fluid characterization. With this technique, fluid contribution to porosity can be directly evaluated. This contribution can then be analyzed as a percentage of the total volume of fluids in the investigated pore spaces.

This determined fluid volume can then be used to compare sections of the reservoir to understand the changes that occur within the formation. When significant increases in oil volumes and corresponding decreases in water volumes were identified, these sections of the reservoir were perforated for production. In all tested cases, water-free or reduced-water completions were achieved. This changed the economic condition of each of these wells by maximizing oil production and minimizing water production.

References Cited

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Smith, C.H., L. Hamilton, and L. Ziane, 2014, Advanced Log Characterization of Complex Carbonate Reservoirs: Paper SPE 170118 presented at the SPE Heavy Oil Conference-Canada held in Calgary, Alberta, Canada, 10–12 June.

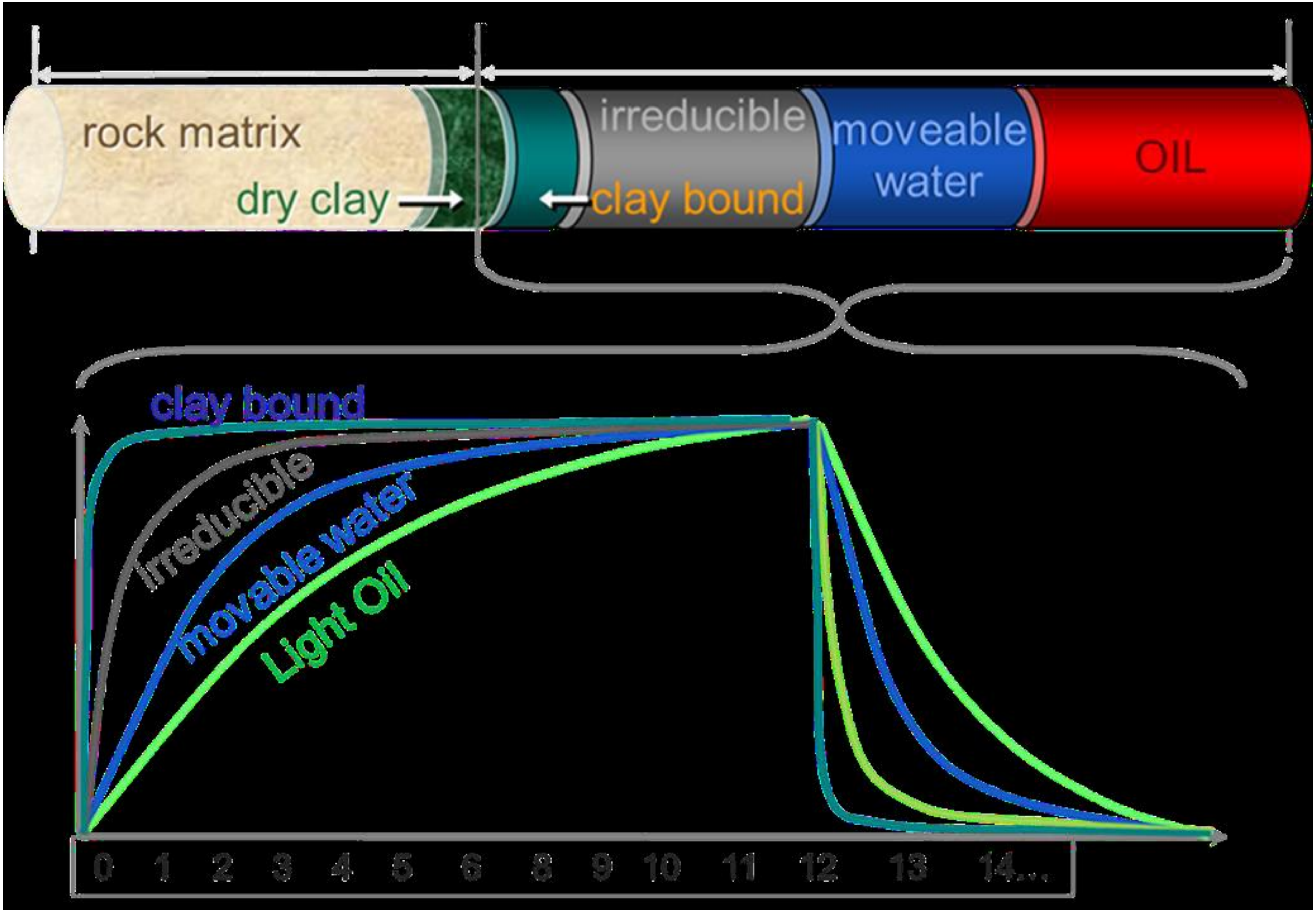

Figure 1. Measurements Made by MR Devices.

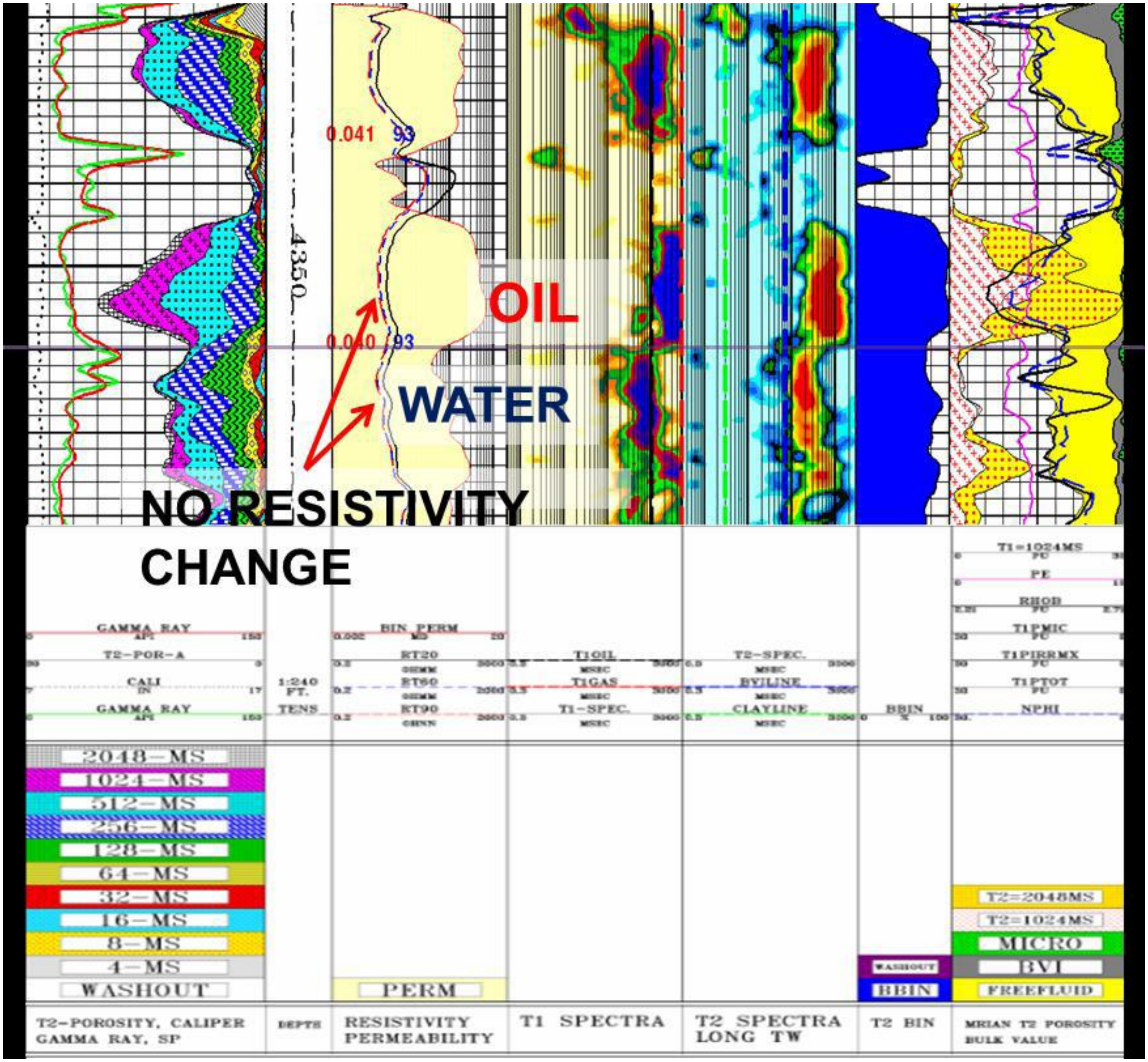

Figure 2. Oil/Water Contact in Mississippian Lime.

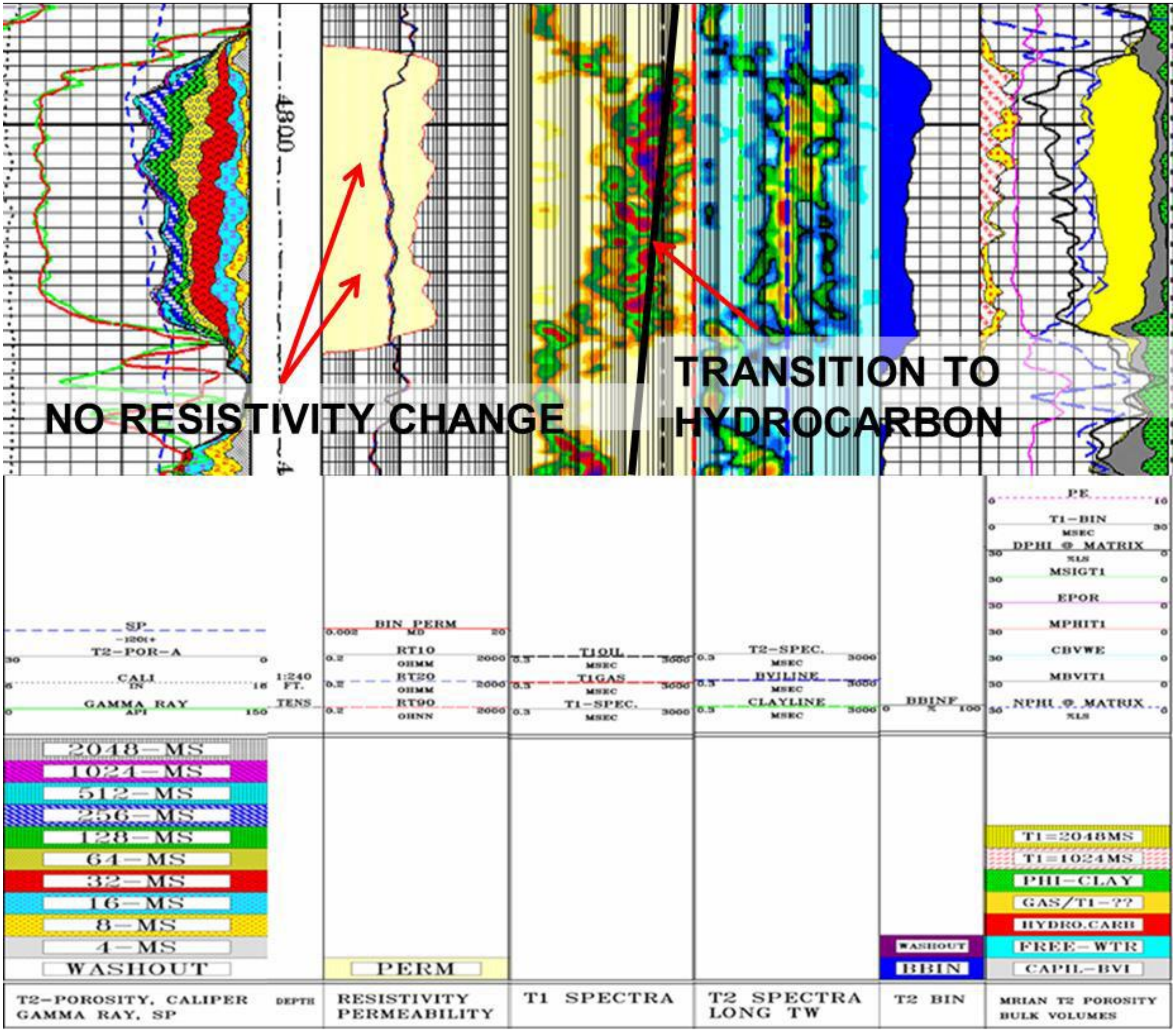

Figure 3. T_1 Transition of Fluids or T_2 Pore Size Effect.

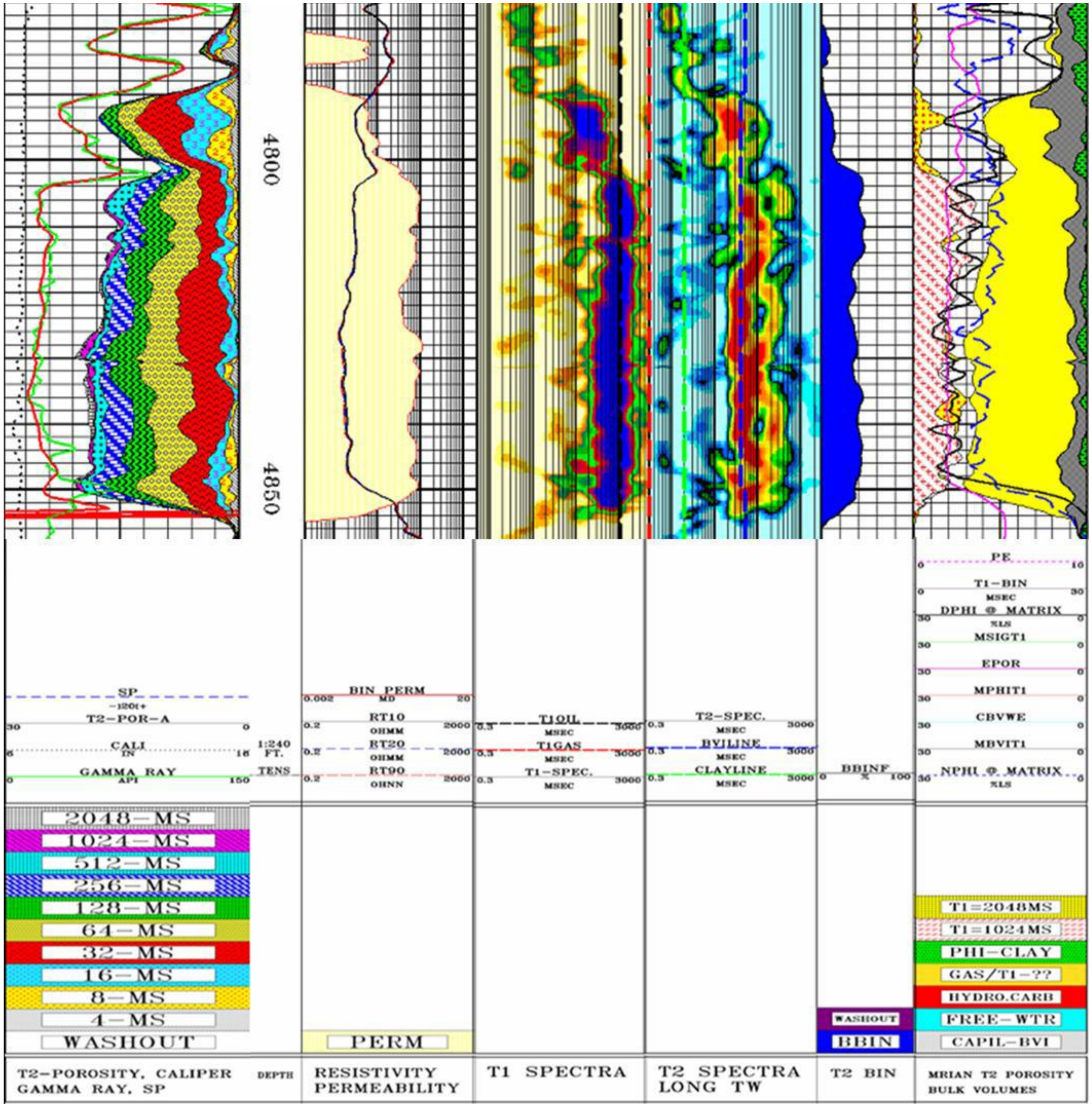

Figure 4. Questionable Fluid Identification from T_1, T_2, and Resistivity.

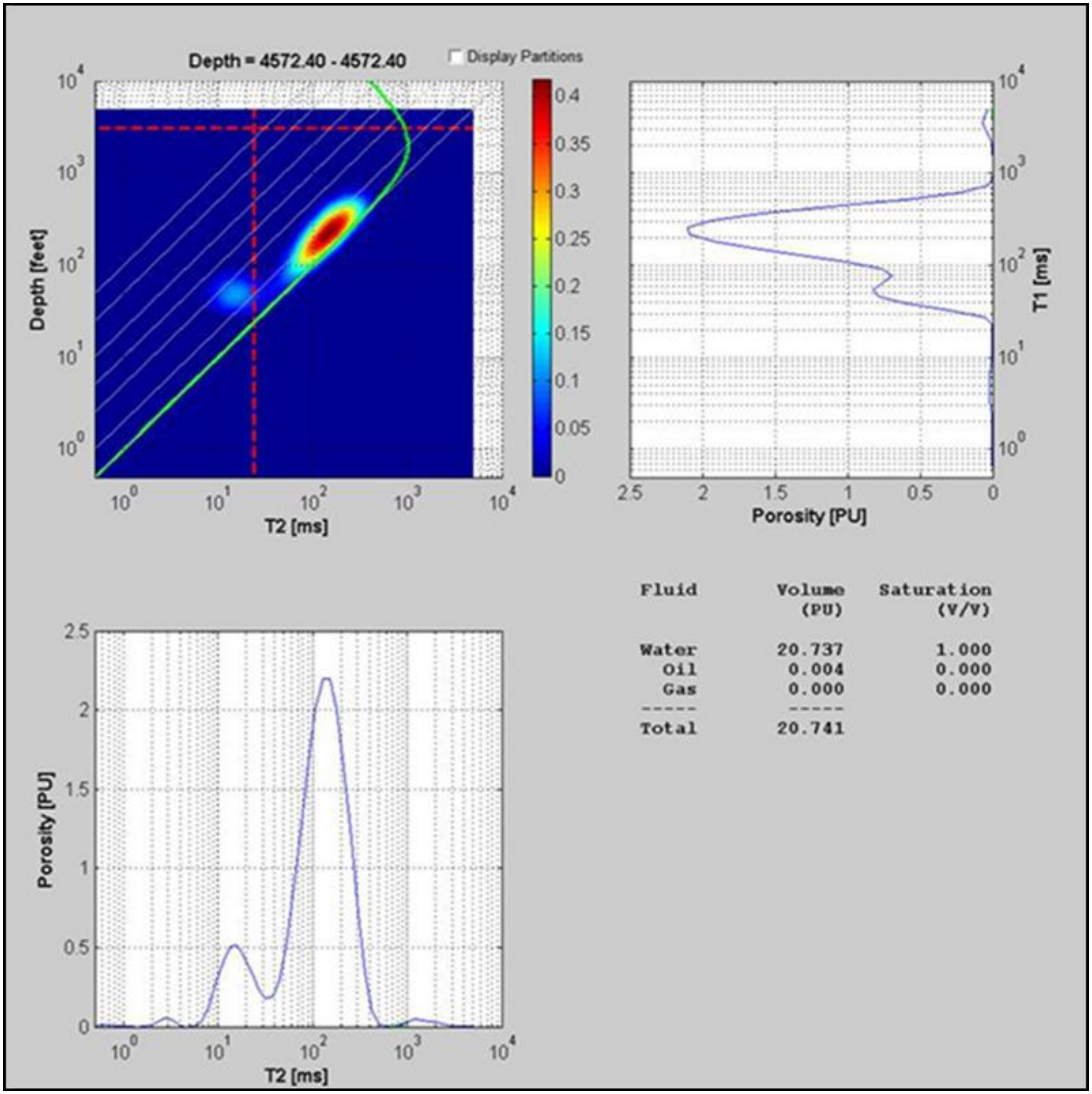

Figure 5. Two-Dimensional Fluid Characterization from MR in Wet Interval.

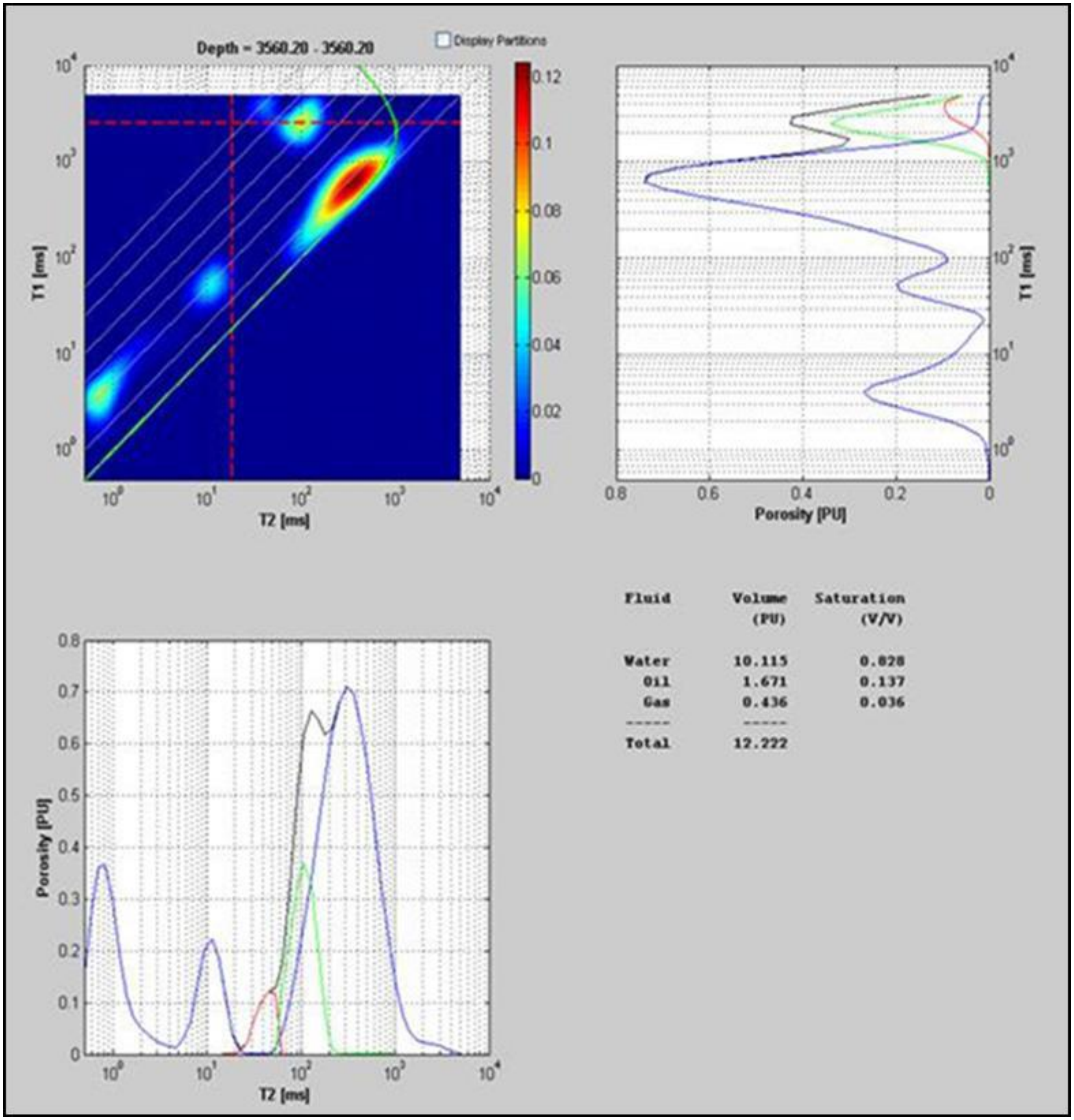

Figure 6. Two-Dimensional Fluid Characterization in Multiphase Fluid Conditions.

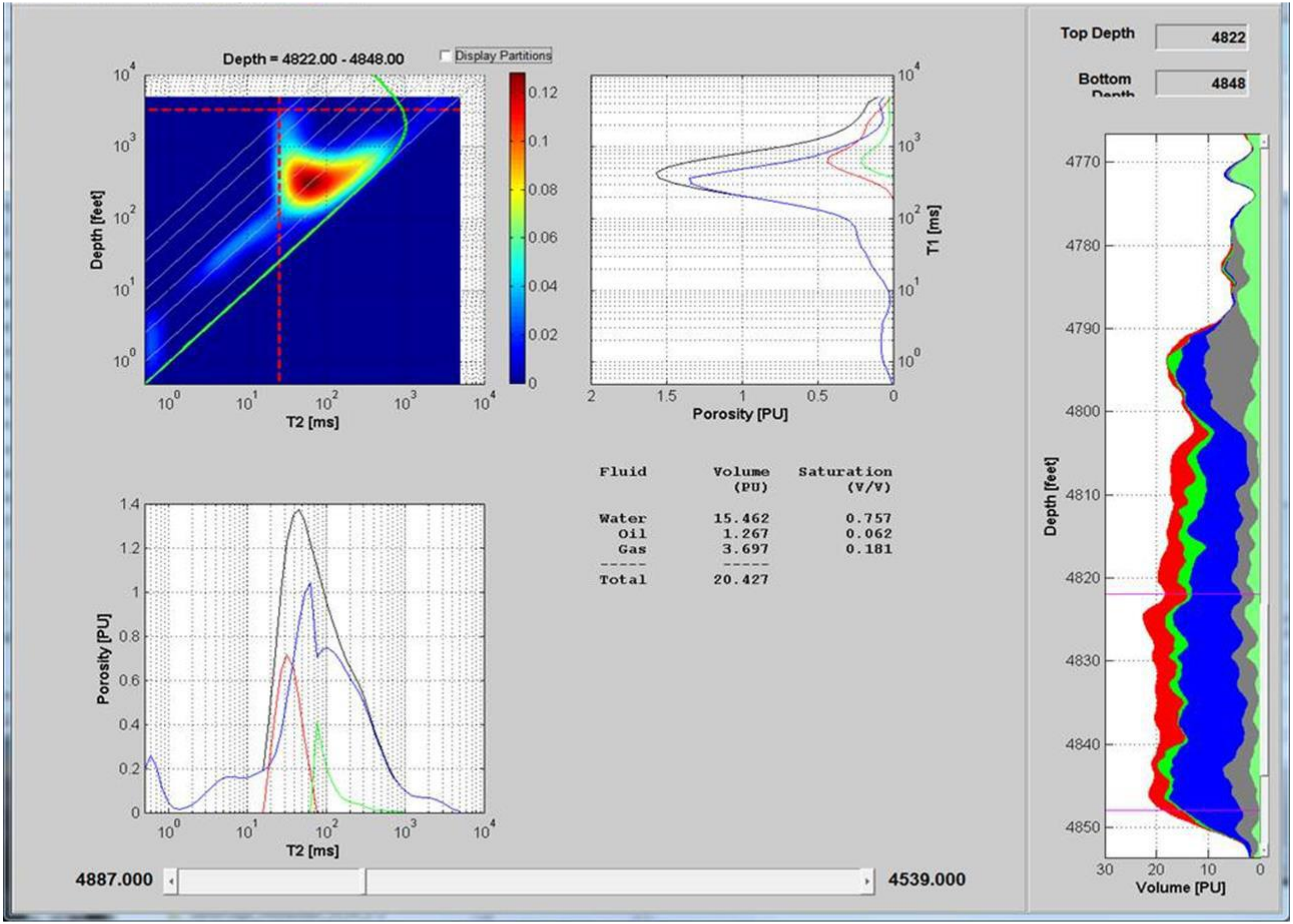

Figure 7. Two-Dimensional Fluid Characterization from 4,822 to 4,848 ft.

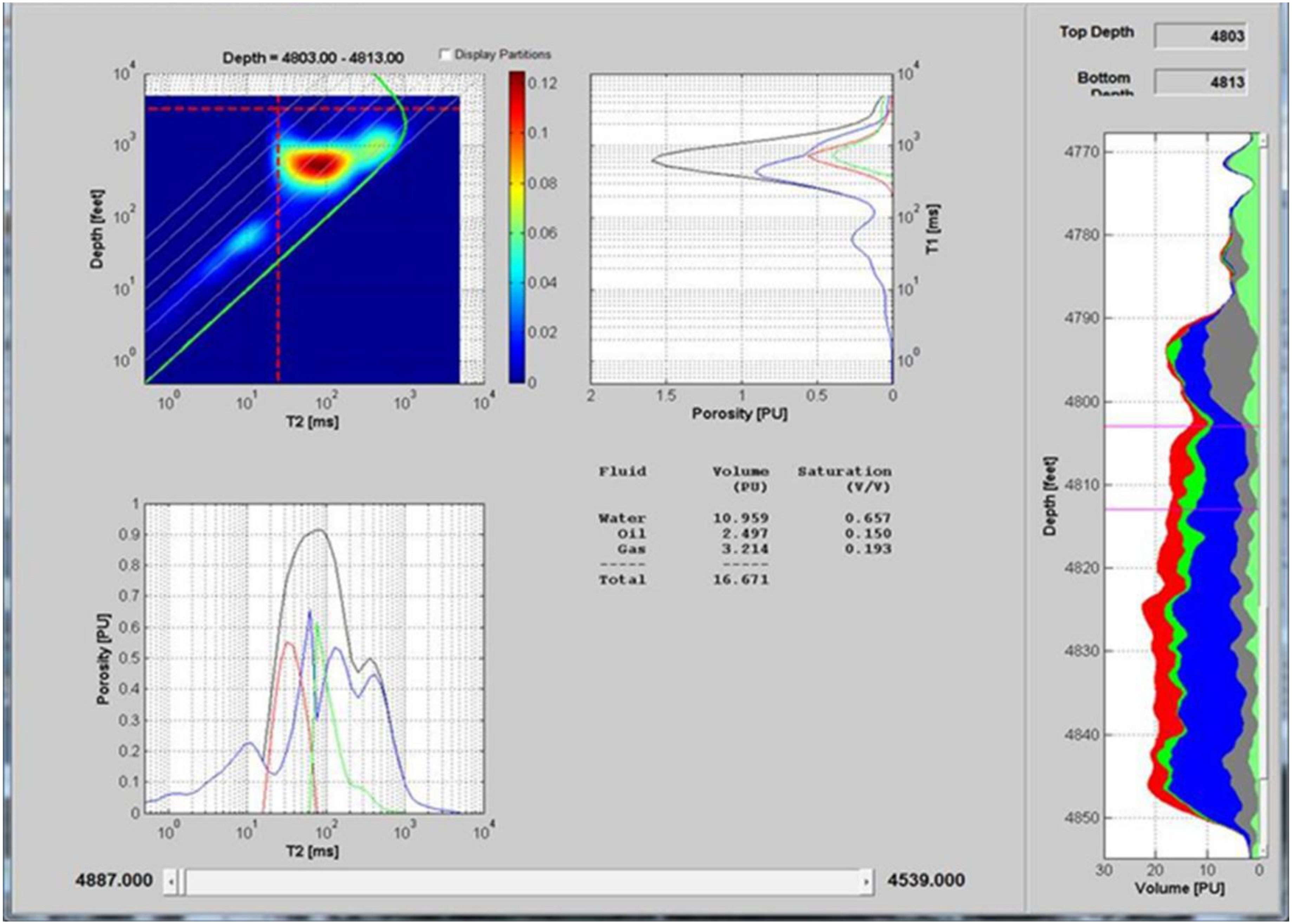

Figure 8. Two-Dimensional Fluid Characterization from 4,803 to 4,813 ft.