SPE/PS/CHOA 117820
PS2008-363

Integrated Petrophysical Approach for Determining Reserves and Reservoir Characterization to Optimize Production of Oil Sands in Northeastern Alberta

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This paper was prepared for presentation at the 2008 SPE International Thermal Operations and Heavy Oil Symposium held in Calgary, Alberta, Canada, 20–23 October 2008.

Abstract

The acquisition of triple-combo logging data, borehole imaging data, dipole sonic, and select magnetic resonance data, offered the unique opportunity to study a specific set of wells in the McMurray Formation of northeastern Alberta. Each one of the data sets provided valuable information about the geologic setting, fluid properties, or rock properties. The true value of the logging data comes from combining the analyses and interpretations to produce a complete picture of the geology, reservoir potential, and production potential. This integrated approach is based on the interpretation of results from the image data, while incorporating standard log data, including electric, nuclear, and acoustic measurements; dipole sonic data; and nuclear magnetic resonance data. Subsequently, shaly sand analysis from these measurements was added to provide key reservoir petrophysical information. Finally, the addition of nuclear magnetic resonance data supplied insight into the producibility of the reservoir.

Traditionally, dipmeter and image results are used for mapping of channel sands in the McMurray Formation. For this application, however, the image data provided high-resolution delineation of shale beds. This use of the image data leads to a critical reservoir heterogeneity description, which is required for vertical permeability information to optimize production. Shaly sand analysis results (volume of shale, sand calculations, water saturation, and permeability) are combined with core data, when available, and both the core and shaly sand analysis results were incorporated along with the image interpretations. Finally, nuclear magnetic resonance data was added for the key wells, providing comparison of bound to free water, as well as permeability and lithology-independent porosity. When combined, each data set adds either qualitative or quantitative information that is iteratively used to refine and complete the integrated petrophysical analysis.

In this investigation of the McMurray sand characteristics, initial interpretation of the image data revealed that the depositional environment does not match that of the typical fluvial-estuarine sands; subsequently, an interpretation of all wireline data was performed. The results of this interpretation indicate a shoreface environment. Integrating all petrophysical measurements enabled geoscientists to obtain a more complete picture of the subsurface.

Introduction

This paper discusses a field study of wells from a project in the northwest quadrant of the Athabasca Oil Sands, which spans several townships. The paper focuses on six wells, spaced according to **Fig. 1** from northeastern Alberta. This case study was approached from the perspective of image interpretation. Many of the wells in this area have been extensively mapped using image log and dipmeter interpretation results.

The typical fluvial-estuarine environment requires mapping of current bedding and lateral accretion surfaces in order to properly place future horizontal production wells. However, the initial results from the image interpretation of these data did not show a relationship with the typical fluvial-estuarine depositional environment. These results prompted a collaborative study between geoscientists who were individually analyzing separate suites of data from this same project. In addition, seven wells in this project were logged with a standard triple-combo suite along with electrical borehole images, dipole acoustic logs, and nuclear magnetic resonance logs. An integration of each data set through an iterative interpretation process revealed that the depositional environment actually matched that of a marine shoreface setting rather than the previously assumed fluvial-estuarine sands environment.

The wells included in this study were found to be from two distinct geological settings. (See map in Fig. 1.) The first area in the northern part of the study area includes the target McMurray Formation, while the southern area contains potential reservoir in both the Wabiskaw and the McMurray formations. (See Fig. 1.) The purpose of this paper is to show that through integration of sufficient data, the geology, reservoir characterization, and even productivity information can be determined and a more complete picture can be attained even in areas with minimal prior comparative data.

Electrical Borehole Image Data

The majority of the features interpreted in McMurray area wells are bedding, lateral accretion surfaces, crossbeds, and truncation surfaces. Generally, bedding is interpreted as low-angle features where shale content is increased. Lateral accretion surfaces were grouped together with bedding in this situation, but usually have a slightly higher dip angle and often show a cyclic rotation of sand and shale. Crossbeds or current beds typically have been identified by closely spaced, higher dip angles in cleaner sands. Truncation surfaces are recognized by the truncation of one bed into another because of erosion or scouring of one channel upon another. These regularly occur above and below crossbedded sand packages and at the base of channels. A typical fluvial-estuarine sequence is depicted in **Fig. 2**.

Upon initial interpretation of the imaging data, it was clear that the geological model differed greatly from what was expected. In this case, most of the sands appeared to be of lower resistivity with either a massive appearance in the McMurray Formation of the northern area wells and the Wabiskaw Formation of the southern area wells or with nearly horizontal bedding with several large shale breaks present in the McMurray Formation of the southern area wells. When bedding was present, there was a general dip trend to the north with variations from the northwest to the northeast. However, none of the typical channel shapes were present from the interpreted image results. For the most part, bedding was below 10° dip angle and had few correlatable patterns in tadpole (dip angle) plots. (See **Fig. 3**.) This general northward dip trend still lends itself to the overall setting of the McMurray geology with drainage to the north; however the placement of the wells with relation to the development of the basin now appears to be seaward, compared to those previously studied. In terms of following the target sands, these data support attempting to drill production wells perpendicular to the low-angle bedding dipping to the north.

Aside from dip data, the image data were also used to qualitatively describe the reservoir. The target zones appear to be finer grained than the fluvial channels mapped in other projects with very thin shale layers within the sandy sequences. Many of these shale beds, however, appear to be discontinuous even within the area of the wellbore. Saturation changes were noticed in some areas with water found at the upper section of the logged interval. This is identified in the image log (See **Fig. 4.**) by the change of resistivity that grades from high to low toward the top of the zone. Water is also identifiable because of the loss of clarity in the definition of shale beds and water sands as they approach equal resistivity. Additionally, several large mud clasts appeared within the shale section; however based on their shape and character, most of the clasts were brecciated and appear to be of very minimal lateral extent.

The next step in the interpretation process was to compare the results shown by the image data to that of the openhole, triple-combo data and shaly sand analysis.

Openhole Petrophysics

The standard openhole logs included induction, density, and neutron. The data from these measurements were used as an input to shaly sand calculations to provide volumetrics for both fluids and lithology. The water saturation was calculated along with permeability. The data were initially processed using generalized McMurray sand parameters and were then correlated to core analysis data. Simandoux shaly sand calculations were used for water saturation determination with parameters of $a = 1$, $m = 1.6$ or 1.8 (1.6 for the shallower sands and 1.8 for deeper sands), and $n = 2.0$. Formation water resistivity was also adjusted in order to properly calibrate water saturations to those obtained in core analysis. Additionally, the minimum volume of shale value calculated from either the gamma ray, density-neutron crossplot porosity, or the spontaneous potential was used to determine volume of shale. As seen in **Fig. 5**, a strong correlation exists between core and log data throughout the zones of interest with the exception of the gas cap, where the log data are affected by the gas. Permeability was calculated using the Wylie Rose equation, although only two wells had core-determined permeability available for comparison. Once correlated, the same parameters were used to calculate permeability in the rest of the study area.

The openhole log analysis indicates that the high porosity in the McMurray Formation in the northern set of wells is similar to that of successful ventures in the fluvial setting and that they average in the mid 30 percent sandstone porosity, which is acceptable for reservoir potential. This compares well with the porosity of the Wabiskaw areas found to the south. However, the McMurray target in the southern region had variable porosities with values ranging from less than 15 percent sandstone porosity to maximums similar to those of the other northern target zones. This variation is primarily due to shale volume and shale breaks found within the McMurray Formation in the southern region. The discontinuity of the pay zone resulting from shale breaks qualitatively suggests that the McMurray target found below the Wabiskaw in the southern study area would be less productive. Permeability calculations show that both the McMurray from the northern area and the Wabiskaw from the southern area are quite homogeneous. Permeabilities in these zones of interest are on the order of three to nine Darcies (D) with little variation throughout the interval. (See Fig. 5.) The permeability in the McMurray Formation from the southern area, however, has large variations ranging from 100 mD to nearly 10 D. This wide variation in permeability is associated with shale content and large shale breaks that will inhibit production and break up continuous pay zones. Here there are more than subtle variations. Overall, continuous pay thickness has been identified as greatest in the northern study area where the McMurray has net pay averaging 10 to 23 m. The southern region may prove to be less productive despite combined total pay thicknesses between the Wabiskaw and McMurray formations ranging from negligible to 33 m. Net pay was determined by limiting the volume of clay to less than 40 percent, including sandstone density porosities greater than 27 percent and bulk volumes of oil greater than 13.5 percent. Furthermore, gas was excluded from pay by removing areas of density-neutron crossover.

Nuclear Magnetic Resonance

Nuclear Magnetic Resonance (NMR) data were collected on the focus wells from the project. These data were used to confirm and support porosity and permeability results from the standard logs. It also helped provide a more complete picture of the fluid volume calculations from the openhole, triple-combo data and offer information about grain size. The eight-second, wait-time data, which includes shale signal, were used from the NMR. These data provided a strong correlation between the results from the openhole petrophysical analysis and the NMR calculations. These results show that the volume of water shown in the openhole petrophysical calculations can be further divided into a free, an immovable, and a clay-bound portion. This results from the fact that the bitumen in the formation is generally not a free fluid, leading to the assumption that the free fluid in the formation is water. From these results, we can see that for production purposes, less water will be produced relative to that shown by triple-combo data, making the target a better candidate for production. (See example in **Fig. 6**.)

In the northern area, the NMR in the McMurray Formation also shows that there is an increase in moveable water near the top of the logged interval. This moveable fluid coincides with a coarsening in grain size and thus a slight increase in permeability. Generally, this moveable water would have to be removed from the overall pay interval estimation, but this interval also often coincides with a gas cap as identified on the openhole logs, which had been removed from pay interval calculations when analyzing the standard openhole logs. Very similar results were seen in the Wabiskaw of the southern study area. The McMurray in the southern area, however, generally had higher water content than the other target zones. A portion of this water was found to be bound but there was often still a significant free portion.

Once again, this information shows that the Wabiskaw in the southern area and the McMurray in the northern area are the best prospects for production. Lastly, a check on porosity is available by comparing the results of the porosities from the nuclear tools to those of the NMR. In the shales, there is a good match between the density porosity and the NMR, where the neutron generally reads a higher porosity. The porosities in the bitumen saturated zones, however, cannot be compared because of the influence of the bitumen on the NMR readings.

Integrated Petrophysical Approach

Upon reviewing the data from each of the petrophysical analyses, the image data were then revisited. Based on the triple-combo data, the primary zones of interest show significant volumes of hydrocarbon despite the absence of the typical McMurray character. The reservoir does show an overall increase in shale content when compared to channel sands. This shale appears in the image log both as thin shale beds, as well as overall finer grained reservoir rock. However, these thin beds are often discontinuous and are too small to have a negative effect on the vertical permeability. After a qualitative comparison of permeability barriers based on the image with the permeability of the target zone, a check was made between the image results and the core photos. There is very good correlation, even including the small shale beds in the area between the core photos and the image log (**Fig. 7**), which supports the reservoir potential for production.

Overall permeability when calculated both with the NMR and the triple-combo data shows very similar results to those in successful adjacent areas. Without additional data, the image log alone produced somewhat discouraging results; however when combined with the data from the other available sources, the image log shows that reservoir is actually quite homogenous with only sporadic areas of shale breaks large enough to act as permeability barriers. When comparing the dip data from the image log on a larger scale, it also becomes apparent that the lateral extent of the McMurray sand in the northern region and the Wabiskaw Formation in the south is quite large, and that only the McMurray target in the southern region poses a large risk due to heterogeneity and discontinuity. This coincides with geological depictions of the upper McMurray and Wabiskaw in more shoreface settings when compared to those of the further inland fluvial-estuarine deposits and supports the possibility for successful exploration and production in these areas.

Lastly, the confidence in each of these interpretations, whether qualitative or quantitative, is increased with each coincidental piece of data, suggesting that the true properties of the reservoir have been found and that the parameters used to correlate the data may now be used to interpret future data sets successfully whether full data suites are available or not.

Discussion

The overall results from this field study suggest that through iterative interpretation and collaboration between engineers and geoscientists, a better understanding of the geology, petrophysical properties, and producibility of a given target interval may be obtained. Without prior data for comparison, the addition of each data set provided a fuller understanding of the reservoir characterization and now leads to solid inputs for future calculations. This supports the collection of several different data types in the initial stages of exploration to provide a solid foundation on which to base further predictions and computations. Without the image and geological data, the petrophysical analysis would have shown that the target areas are producible and would have supported future exploration. However, with an understanding of the geology and regional trends based on the image data, well placement can become more efficient with each successive well. The NMR provided confirmation of the petrophysical analysis from the triple-combo data and aided in discerning whether the fluids in the reservoir were free or bound.

Conclusion

In conclusion, the majority of the data collected in this project were compiled to aid in the overall interpretation of several target intervals. A geological setting that was different from what was expected has been identified and interpreted to have production potential. Several opportunities exist for future study of the current wells, as well as future wells drilled within the same area. The dipole acoustic data were not used as inputs into the model but would provide opportunity for further study of the rock properties in the zones of interest and offer correlation with seismic data for modeling the play on a larger scale. Future studies would likely include image petrophysics to remove the subjectivity of the image log analysis by applying similar parameters to associated zones. With this method, the grain size, texture, homogeneity, and permeability can be evaluated quantitatively based on the high-resolution resistivity data from the borehole image log.

Acknowledgements

We would like to thank Xianfeng Zhang, formerly of Weatherford Canada Partnership for his contribution in the initial processing and interpretation of borehole image data along with Paul Pavlakos of Weatherford Canada Partnership for his contribution to the processing and interpretation of the NMR data.

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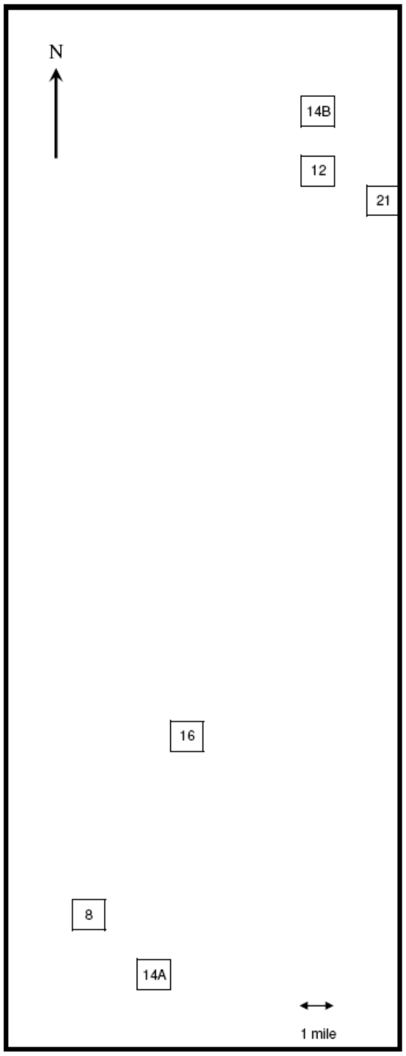

Figure 1. Scale map of focus wells within the project area.

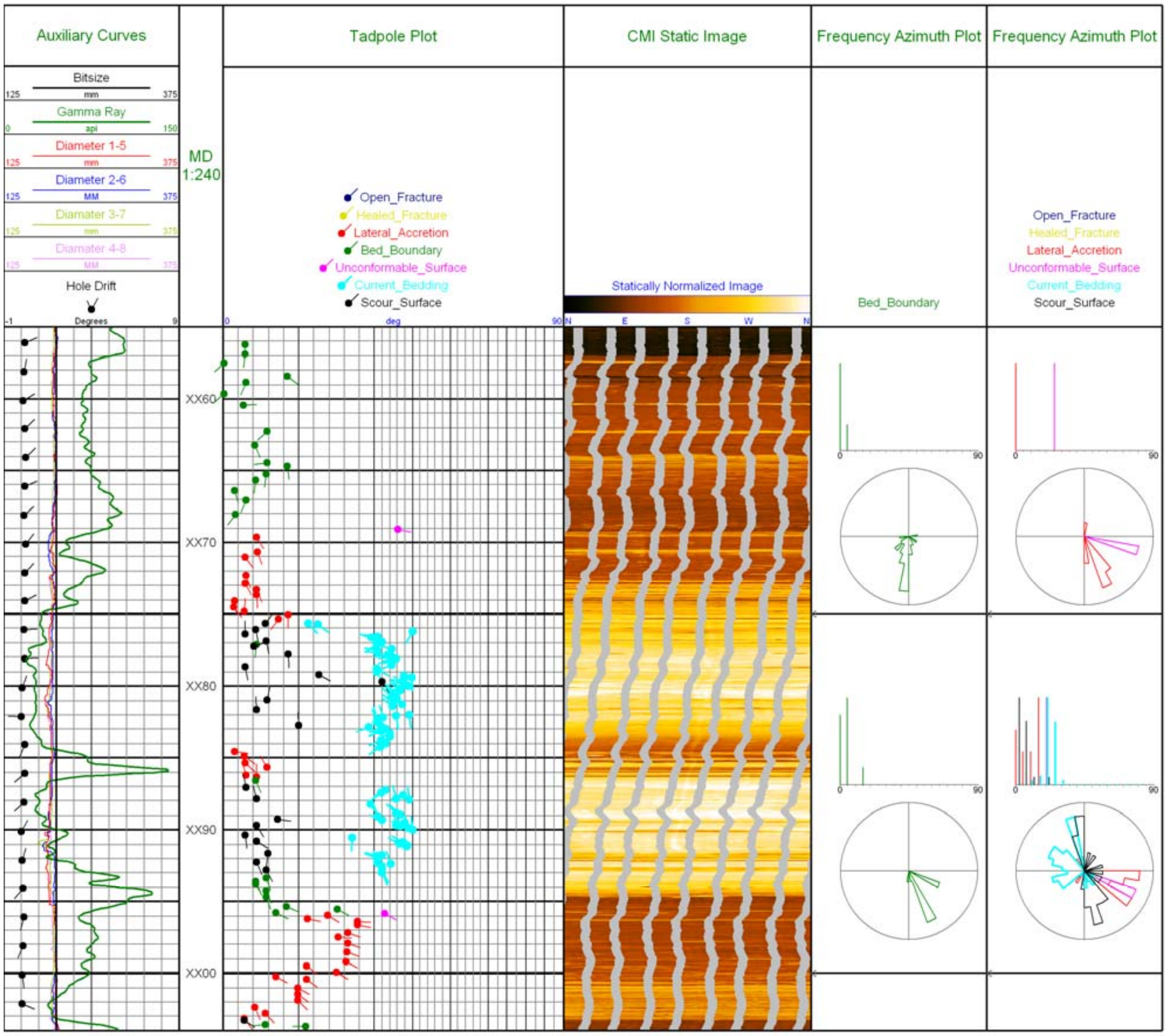

Figure 2. Example of image log interpretation of fluvial-estuarine McMurray well.

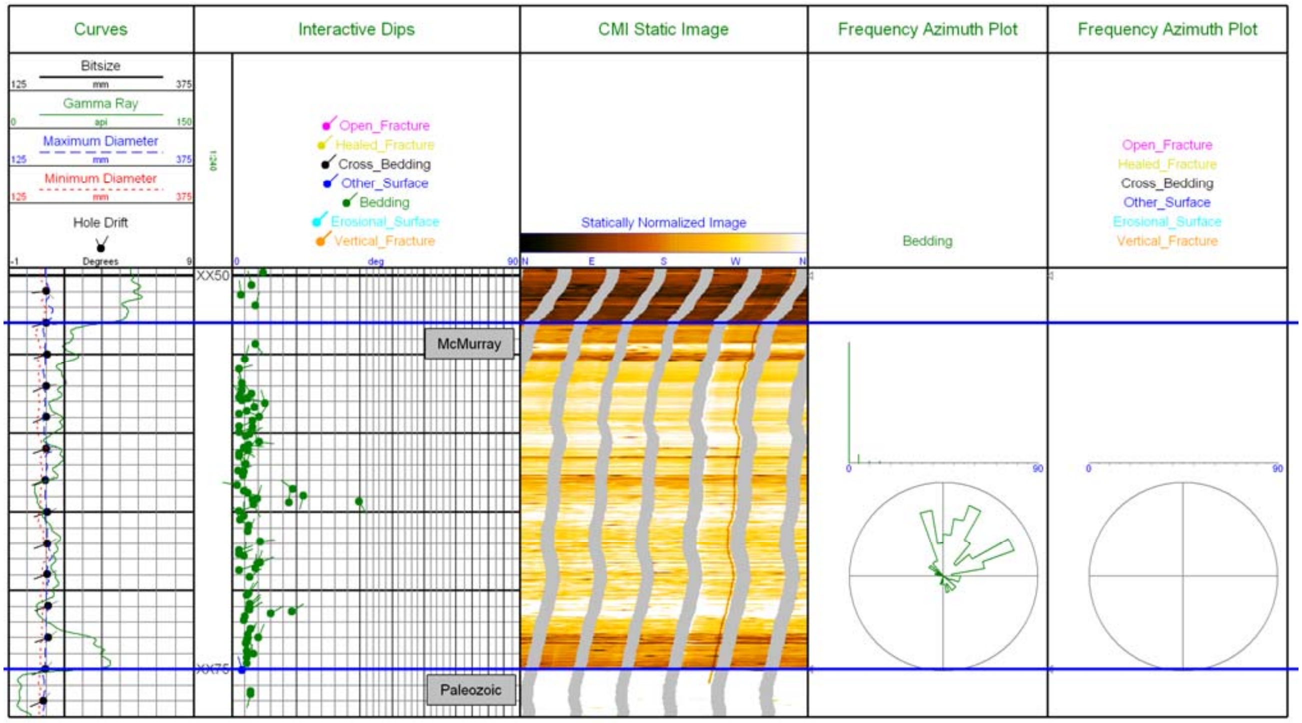

Figure 3. Example of tadpole plot with low-angle beds dipping generally to the north in Well 12 of the field study.

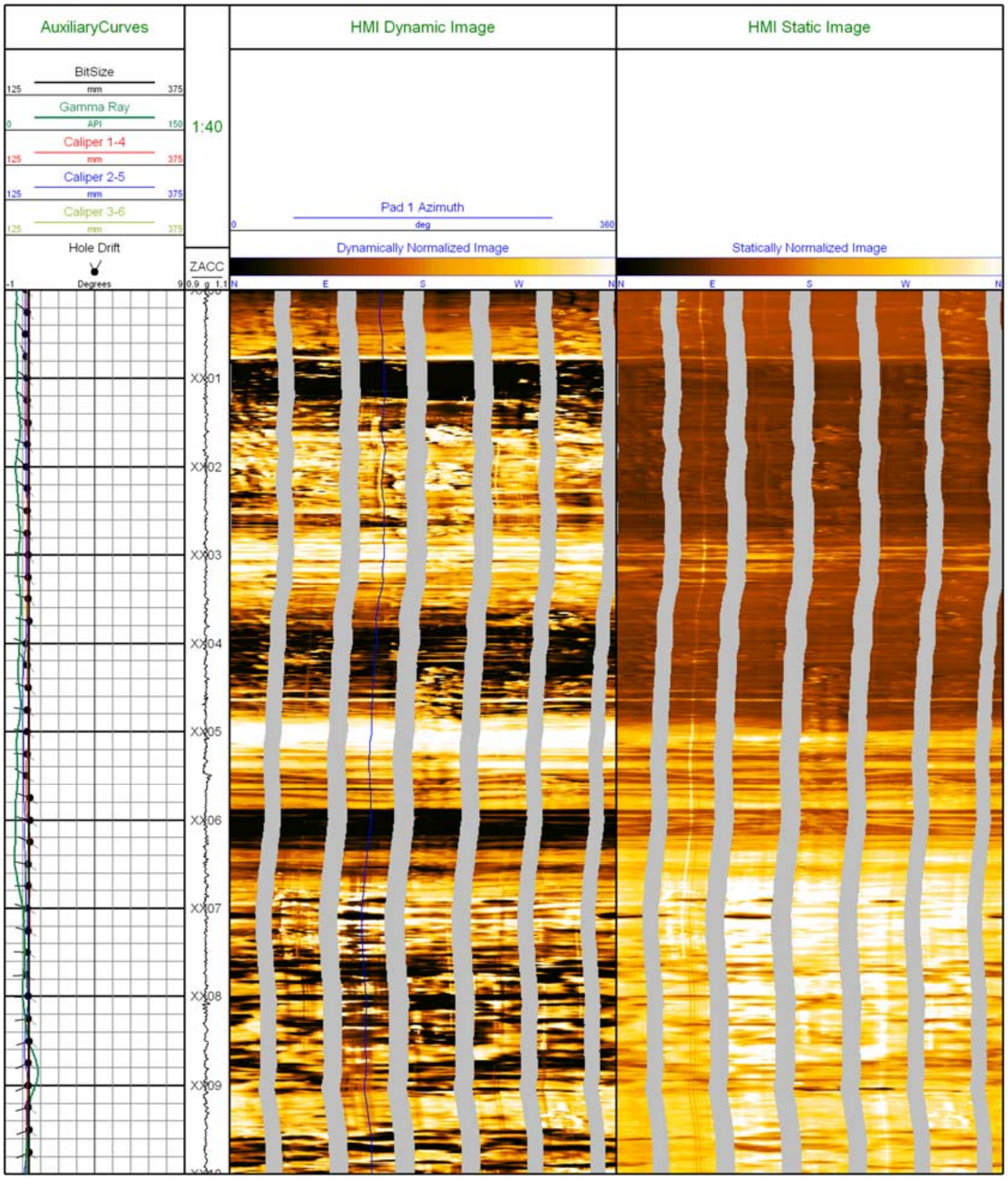

Figure 4. Resistivity change associated with increased water saturation at the top of the Wabiskaw in Well 16.

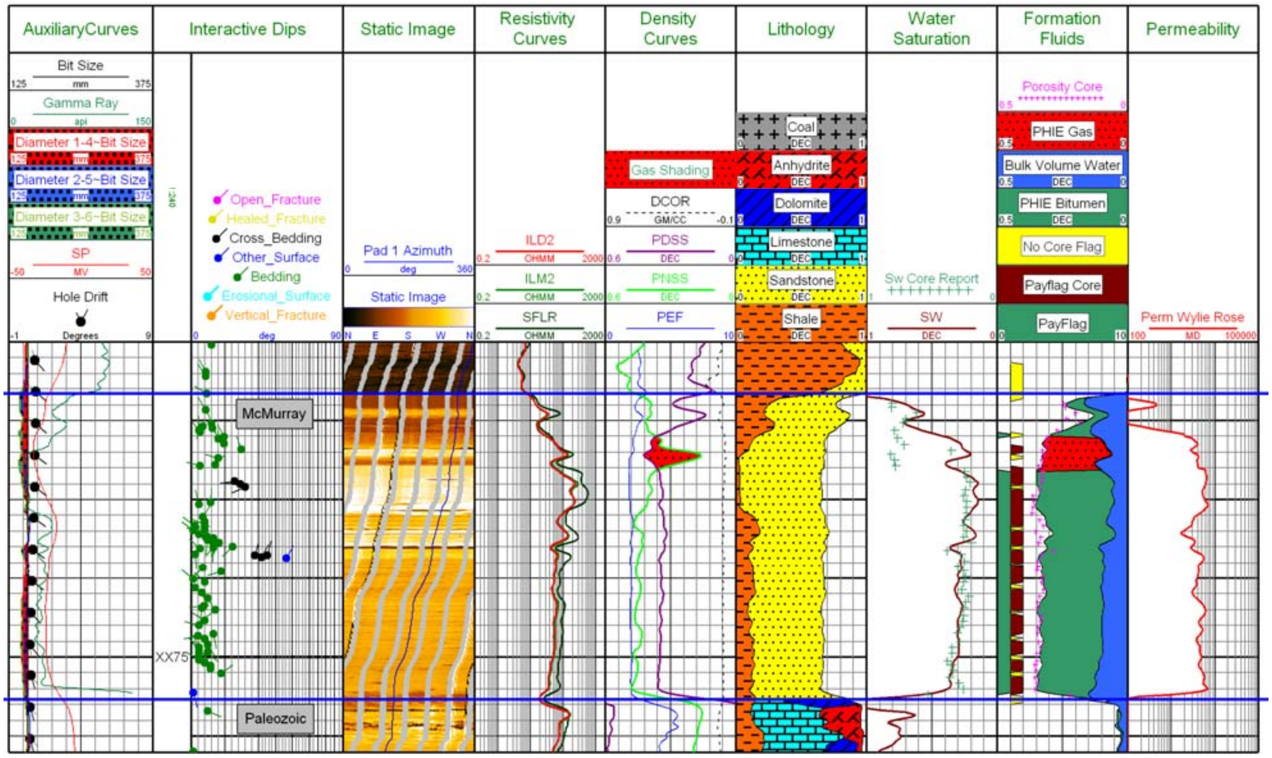

Figure 5. Shaly sand presentation illustrating log-derived and core-evaluated petrophysical properties of Well 14B.

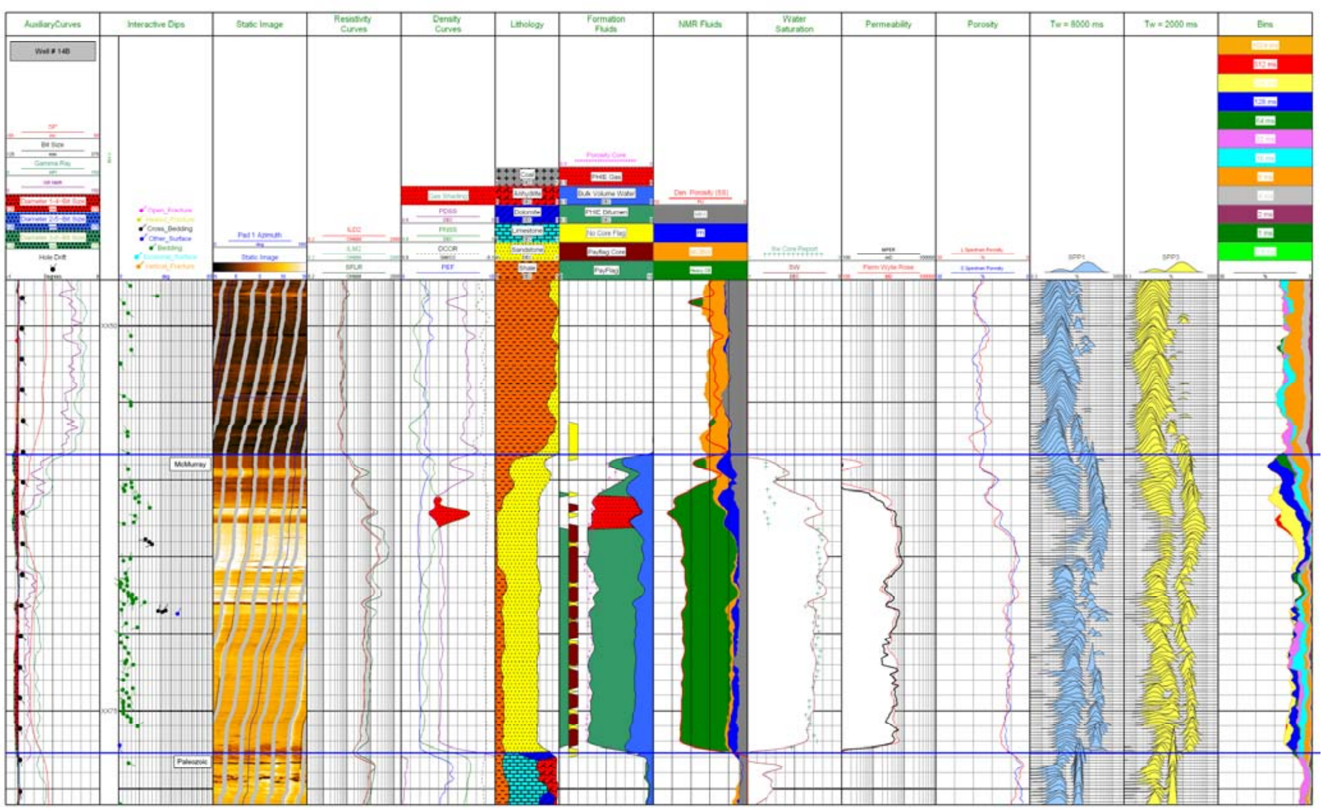

Figure 6. Nuclear magnetic resonance data integrated with image and openhole petrophysical analyses.

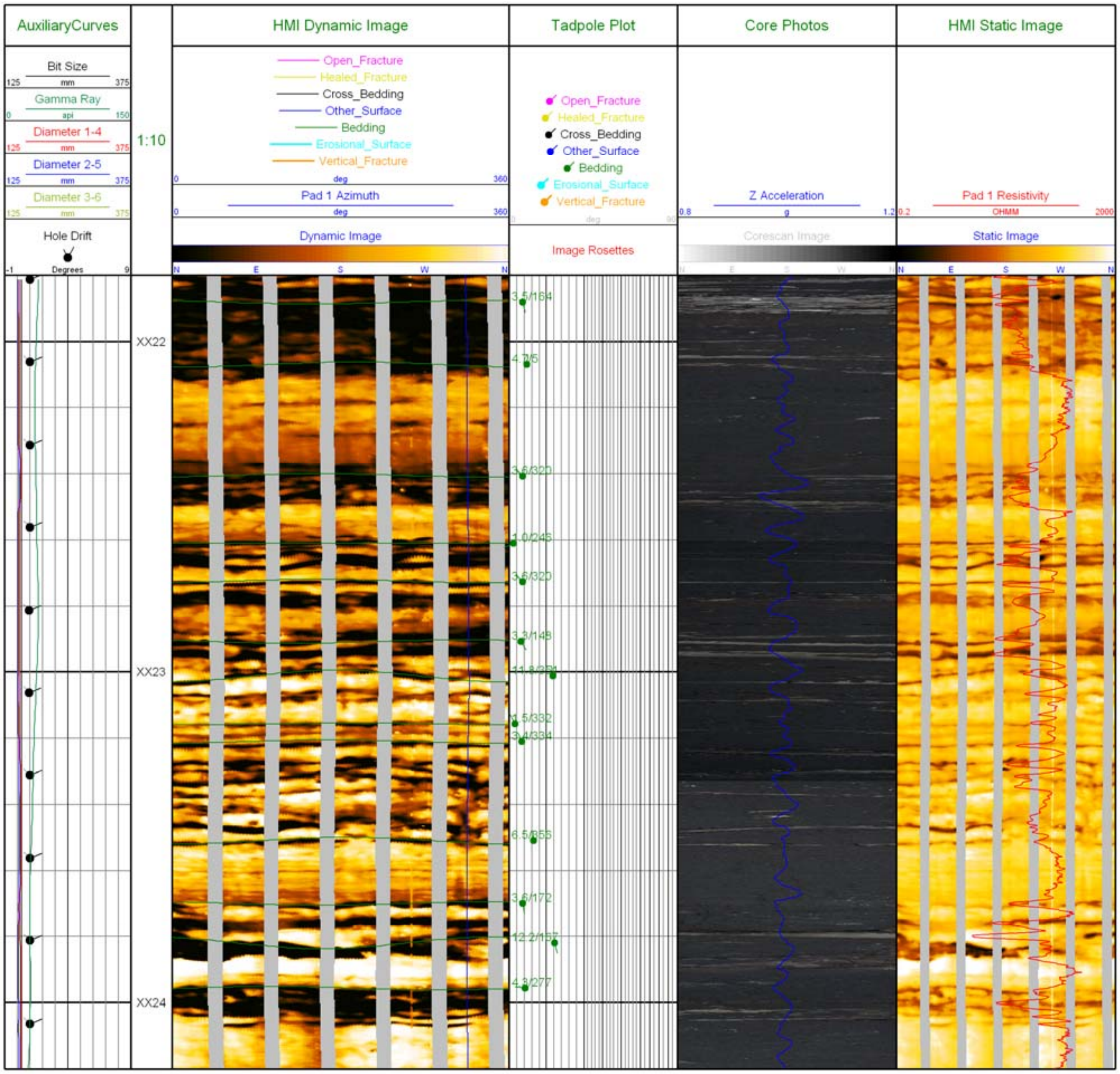

Figure 7. Core photo integration comparing shale thin beds from core photos to image log.