HETEROGENEITY ANALYSIS OF OIL SANDS CORES

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ABSTRACT

Thermal recovery of bitumen in oil sands requires the ability to propagate steam within the formation, and to have drainage of heated fluids to production wells. As such, reservoir heterogeneities can play a very significant role in these processes. Many of these heterogeneities are not easy to define at the scale of logging tools. The objective of this study is to develop a work flow and set of output parameters that can provide a much higher resolution characterization of heterogeneities present in an oil sand, based on non-destructive testing of core. Oil sands cores with variable quality of sand and shale were acquired and tested using an ensemble of techniques including CT scanning at 1mm intervals, continuous NMR and EM sweeps. The continuous NMR is done by moving the core in 1 cm intervals and then de-convoluting the signal from subsequent echo trains to extract information in high resolution. The EM sweeps are done using two different designs of probes (one induction and one plate design). Density and porosity are extracted from CT. Oil and water contents are extracted from NMR and CT porosity. Resistance is extracted from the induction probe and frequency dependent capacitance is extracted from the plate probe. All the information is then reprocessed together to extract a number of data in a high resolution log of the core. Although the initial interest is in the quantitative distribution of the V-shale parameter, the results can be used to characterize heterogeneity in both porosity and fluid distributions within the core.

INTRODUCTION

When conducting experiments in oil sand cores we often experience very poor injectivity and very low permeability to water at initial core conditions. When core selection is done based on logs, the core intervals appear homogeneous but at the core scale, local heterogeneities are observed. As oil and gas development moves towards less homogeneous sands, the log resolution for heterogeneity detection is inadequate. An alternative process is demonstrated in this paper. Several core pieces from an oil sand well were collected to demonstrate the work flow intended in high resolution heterogeneity detection. The core pieces represent various oil sand layers containing inclined heterolithic stratifications (IHS) some with more sand and some with more mud, as well as breccia and cap rock. The core pieces were slabbed and kept frozen, but the core was found to be desiccated at the start of the tests. Thus the core had to be hydrated. All pieces were soaked with predefined amounts of fresh water, which was dripped onto the surface of the core. Following that, the pieces were weighted and wrapped to maintain moisture. All core pieces underwent CT scanning, continuous NMR scanning

and two novel EM sweep procedures. Each of these modalities was analyzed independently and the results were combined to provide an integrated characterization. The difference in resolution of the different modalities does not allow for simultaneous treatment of all the results. Thus, for the purposes of this work the modalities are interpreted sequentially.

SCANNING METHODS

X-ray Tomography

The core was scanned in 1mm intervals at two energies (120 and 100kV) [1, 2]. However, dual energy contrast was not sufficient for atomic number characterization. Thus only the high energy scans (proportional to density) were used in the interpretations of this study.

CT image analysis creates density maps for each slice. The density numbers for each pixel of a given slice are plotted and a density distribution is generated for each slice. In a uniform sand (40% porosity) this distribution is a Gaussian with a mean at around 2,000kg/m^3 and a fairly narrow standard deviation (approximately 20kg/m^3). Lower densities denote more porous sands and at some point lower densities denote sand parting (or coring induced dilation) and presence of fractures. When higher densities are present in the distributions, depending on the shape and size of the density areas, one can get boundaries for shale (clay laminations), pebbles, and inclusions such as siderite or pyrite.

The precise cut-off points depend on the machine used and the size of the core sample. Thus it is very difficult to provide unilateral numbers. The most precise method for identification of each density domain (sand, clay, pebble and siderite) would be through statistical deconvolution, coupled with pairing against other data (e.g. particle size analysis). This method is currently under development. For the current report the simplification of cut-off points (used commonly in NMR for phase determination) is used. After the cut-offs are determined, the density images are reprocessed and the four domains are created. Currently, the sand is split in two domains sand and the rest as shale. V-shale is determined as:

$$V_{shale} = \frac{Volume\ of\ clay\ domain}{Total\ slice\ volume} \quad (1)$$

V_{shale} is then plotted as a function of depth.

Low Field Magnetic Resonance

An NMR scanning system for full diameter core was created for testing native cores and also for core used in full diameter core floods. The system does not have gradients for NMR imaging. Instead spectra and T_2 relaxation time distributions are measured. The system used in this study scans core at 30cm intervals (NMR sensitivity area – sweet spot). In order to generate higher resolution measurements, the core was scanned, moved in 1cm intervals and scanned again. Thus in two successive NMR scans, 29cm of the core within the sweet spot would be the same and 1cm would be different.

A proprietary algorithm was created that takes these successive scans and de-convolutes them to provide spectra of approximately 3cm intervals. These spectra are then further decomposed to provide amplitudes of oil, clay bound and capillary bound water. When this is done, the NMR estimate of V_{shale} is calculated by normalizing the clay bound water amplitude to the total amplitude as follows:

$$V_{shale} = \frac{A_{clay}}{A_{clay}+A_{cap\ water}+(A_{oil}/RHI)} \quad (2)$$

Given the appropriate cut-off points the only unknown is the value of the relative hydrogen index (*RHI*) which denotes the relative signal strength of oil as compared to the same volume of water. If the reservoir oil is homogeneous with depth then an oil sample can be tested and the *RHI* number can be extracted. However, if the oil is not homogeneous then Equation (2) is not sufficient to provide an accurate V_{shale}. As an alternative, a clay indicator (*CI*) can easily be created through Equation (3).

$$CI = \frac{A_{clay}}{A_{clay}+A_{cap\ water}} \quad (3)$$

Small values of *CI* ($CI \rightarrow 0$) indicate sandy environment, while large values ($CI \rightarrow 1$) indicate shale.

Electromagnetic Sweep Measurements

With the increasing popularity (at least in the research world) of electromagnetic heating technologies for oil sands heating and bitumen recovery [3], there has been an increased effort in understanding the dielectric properties of reservoir rocks and in particular oil sands. When a rock sample is exposed to electrodes and then a variable frequency sweep is applied on to it, measurements of capacitance and resistance can be made. Given appropriate calibrations, these measurements can be translated into resistivity and dielectric constant measurements as functions of frequency. If the electrodes cannot touch the core, then the resistivity measurement becomes more problematic, but there are still ways to calculate dielectric constant [4].

When a partially water saturated sand is exposed to an EM sweep, the resulting conductivity and dielectric constant dispersions with frequency are recorded. The conductivity (real component of complex impedance) dispersion is relatively flat and is greatly affected by the amount and salinity of the water present in the core. The dielectric constant (extractable from the imaginary component of complex impedance) is also affected by the same parameters but the dispersion is much stronger. This is the principle of the new dielectric logs [5] but the frequencies used for the EM sweeps in this work are a very small fraction of the log sweeps. When it comes to clay, conductivity dispersions should be different than sand's and the dielectric constant dispersions should be distinctly different than those of sand.

In order to extract conductivity and dielectric constant from resistance and capacitance, details of what is the equivalent circuit of the core and the environment must be constructed [6, 7]. This aspect for a complete core with vertical heterogeneity is still under investigation. Thus in this paper data of capacitance and resistance are presented. In order to capture resistance data, an induction coil probe was designed and implemented. In order to capture capacitance data, a parallel plate probe was designed and implemented. All the core pieces were scanned at the maximum spatial resolution possible of approximately 1cm per measurement. The frequency range used was between 0.08MHz and 20MHz. The useful data were between 0.1MHz and 10MHz.

The Core Log Suite

When combining all the recovered data, and allowing for adaptations that will give comparable resolutions, the following information can be obtained.

CT Scanning: **Density profile**, separation in different domains, with knowledge of grain density per domain **Porosity profile**. From density profile and domain identification **V-Shale profile**.

NMR Scanning: Water amplitude profile and subsequently (through combination with porosity) **Water Saturation profile**. Oil amplitude profile. If *RHI* is known then Oil Saturation and V-Shale can be calculated but at this point *RHI* is considered unknown. The Geometric mean relaxation times from water and oil phases are calculated.

Combination of CT and NMR: From the water saturation profile and the porosity profile the **Oil Saturation profile** is extracted. From oil amplitude profile and using the oil saturation profile and V-shale profile the ***RHI* profile** is extracted. From the Oil Amplitude geometric mean relaxation time and *RHI* profile the **Oil Viscosity profile** [8] is extracted.

EM Sweep: **Resistance** and **Capacitance** profiles. There is correlation between capacitance profile and clay content.

RESULTS

Figure 1 shows the photos and CT reconstructions of several pieces of core. It is evident that the photography, no matter how high quality, does not capture all the heterogeneities of the samples. This is especially evident in oil-bearing regions of the core, which show up as simple black uniform-looking zones in the photographs. Figure 2 shows the detailed NMR spectrum of a sample of bitumen and water representative of the area. The fastest relaxing peak represents oil, the slowest relaxing peak represents water in bulk and the smaller peaks in between represent various water in oil emulsion droplets.

Figures 5 and 6 show the calculated shale information from CT (Equation 1) and NMR (Equation 3) for the four core pieces. The bulk heterogeneity levels are captured. The porosity variability was captured as expected and in not shown here for brevity. The fact

that the core is not perfectly preserved does not allow for reservoir predictions but demonstrates clearly the capability of the technique. Equation 3 rather than equation 2 is used here for many reasons. In the clay zones in this core, the NMR clay water content increases and the capillary water drops. When comparing CT and NMR we get qualitative agreement but quantitative agreement was not always achieved. Trend wise CT and NMR calculations are aligned. In the case of cap rock (piece 9) and IHS, both CT and NMR are successful. CT with its finer resolution provides better description of the IHS. NMR does not have the spatial resolution. However, NMR shows high Clay Index in areas (particularly in piece 16A), where CT shows nothing. Utilization of equation 2 would be much better but the inter echo time values used in full diameter coils is not sufficient to extract enough points for a clear description of the oil peak of the equivalents of Figures 2-4. Alternative approaches are sought. The NMR signal of high clay content shown in piece 16A is believed to be correct. But since the scanner does not pick up distinct laminations we believe that the clay is more dispersed rather than layered.

Figures 5 and 6 show two samples of capacitance measurements from the EM sweeps. It can be seen that sand and shale have distinctively different capacitance signatures. The observed scatter of the experimental data below 80 kHz is due to experimental limitations and the data at those frequencies are not used. By looking at the capacitance profiles we can detect two distinct regions which can be fit in simple power functions. From the presented examples we can see that the slopes of these functions are different for IHS and oil sand. However, since the salinity is not independently measured it is difficult to quantify the results into a predictive tool. Figure 7 shows a few such distinct profiles from different parts of the core samples. The signatures are distinct and can be collected in 1cm intervals. However, at this point there is not much more that can be said. Moreover, it is noted that the core areas that are expected to have dispersed clay have a capacitance signature that is a mixture of the two distinct shale vs. oil sand signatures shown in Figure 7. Work in this area continues.

The major drawback of this work was that the core was dehydrated to begin with and that did not allow for more quantitative water/salinity based measurements. It will be very productive to repeat such measurements in fresh core. Currently direct contact with the core provides much more accurate measurements but this is difficult to achieve and guarantee that oil sand core integrity will be maintained. The smaller the core diameter the easier the smaller the coil that can be used. Subsequently the inter echo time can be faster and the method will be able to capture more of the bitumen signature (relaxing faster than 1ms and even below 0.1ms) for a better description of the fluid distribution. The capacitance measurements show great promise even though they are at much lower frequencies than those of the dielectric logs.

CONCLUSIONS

- Single energy CT scanning with density profile deconvolution provides detailed V-sand vs. V-Shale discrimination.
- Discrimination of clay bound water vs. capillary bound water provides a second V-sand vs. V-Shale discrimination.
- The EM sweeps indicate that shale and sand have distinctly different capacitance responses with varying frequency.

ACKNOWLEDGEMENTS

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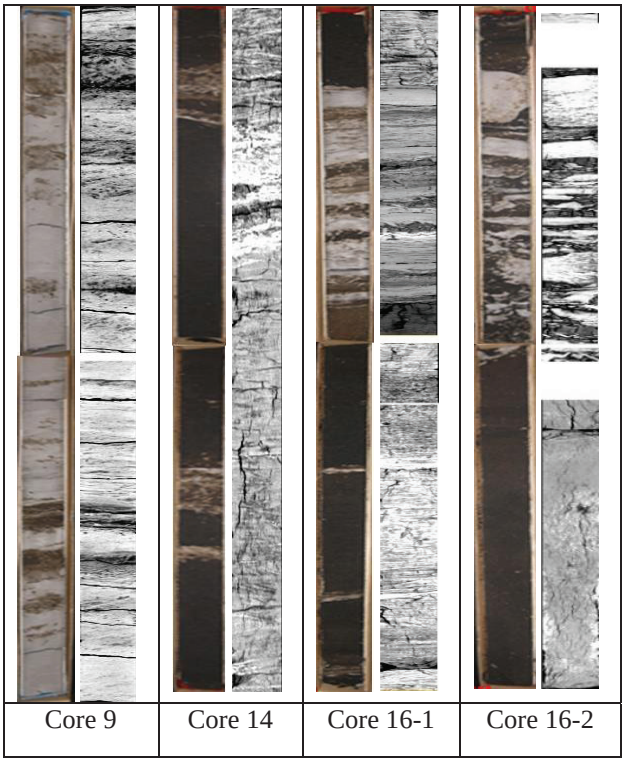

Figure 1: Core photos and corresponding CT image sequences

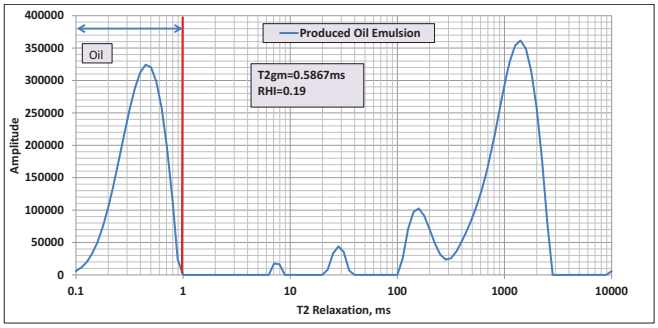

Figure 2: T_2 relaxation distribution of produced bitumen emulsion

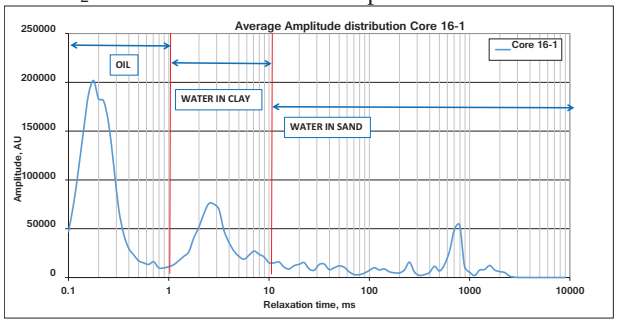

Figure 3: T_2 relaxation distribution of oil rich core

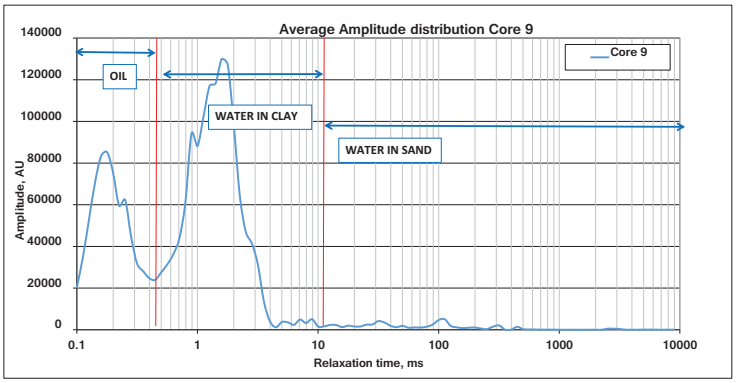

Figure 4: T_2 relaxation distribution of clay rich core

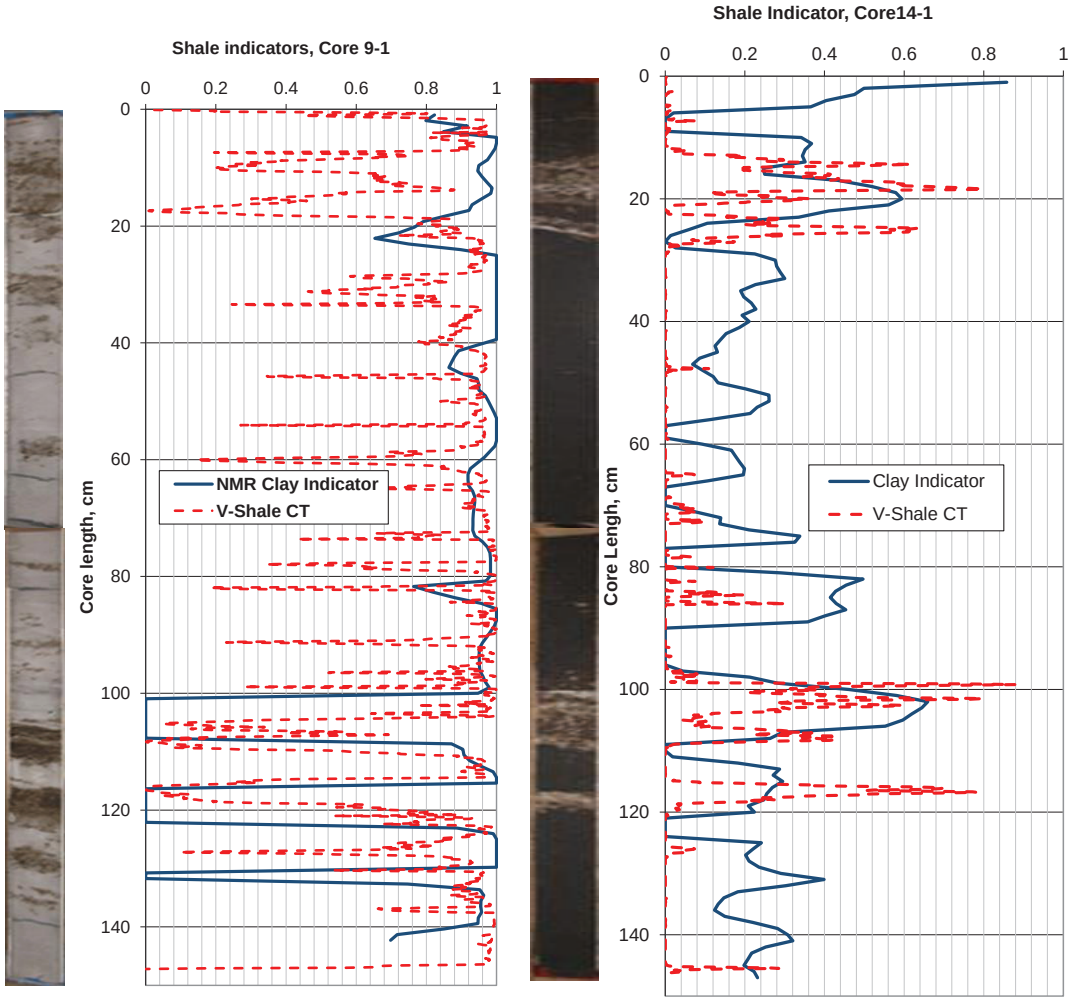

Figure 5: CT V-Shale and NMR Clay Indicator Comparison Cores 9 and 14

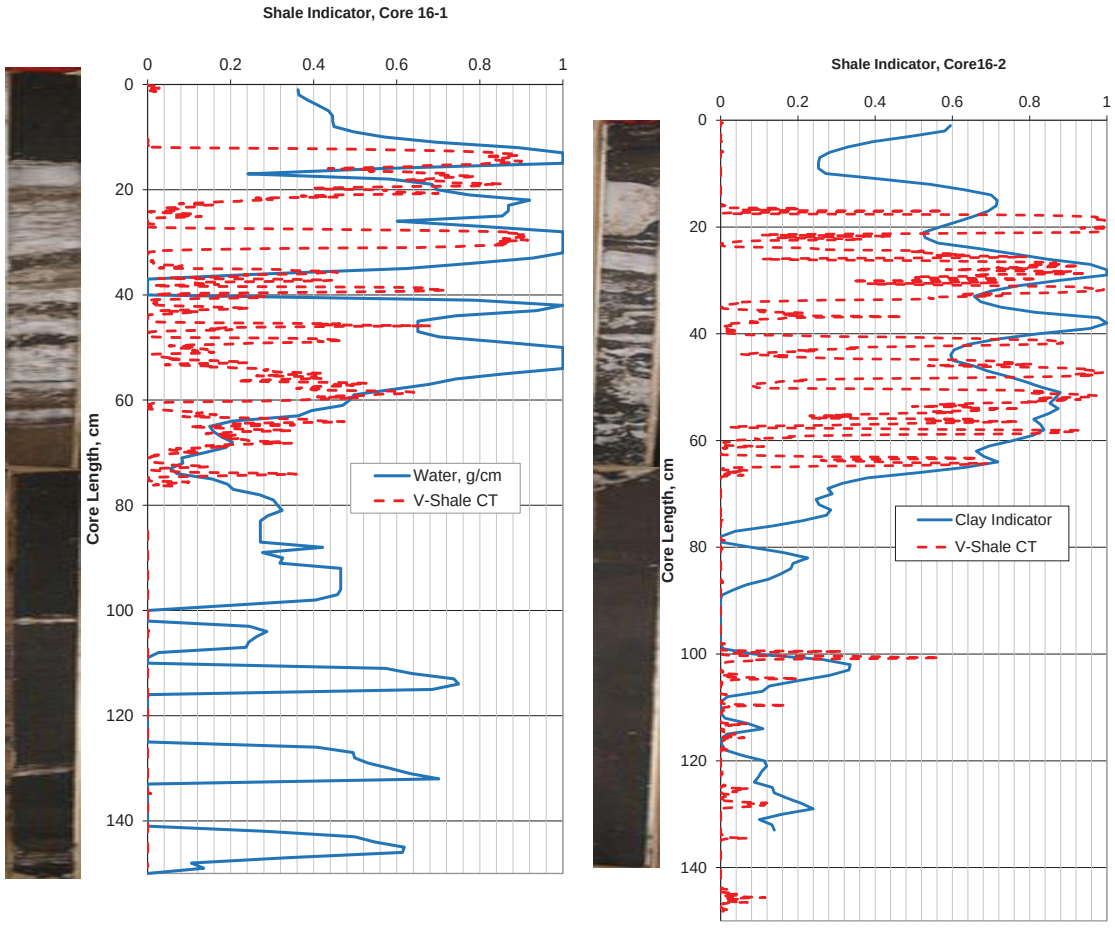

Figure 6: CT V-Shale and NMR Clay Indicator Comparison Cores 16A and 16B

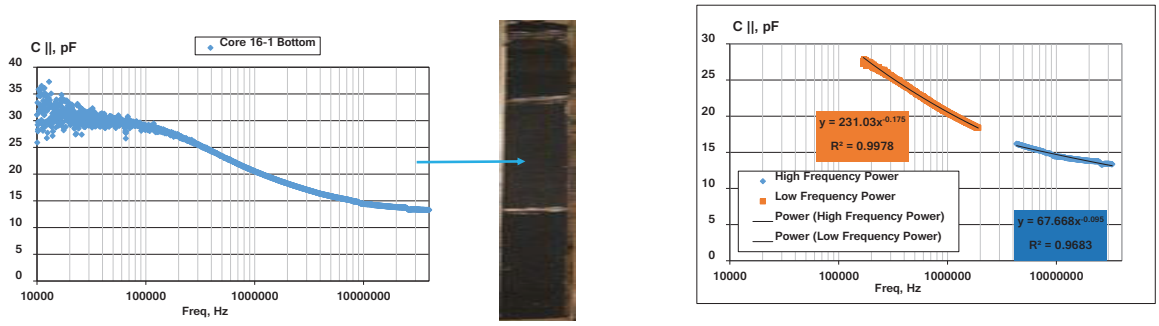

Figure 7: EM sweep and power fit from an oil sand sample

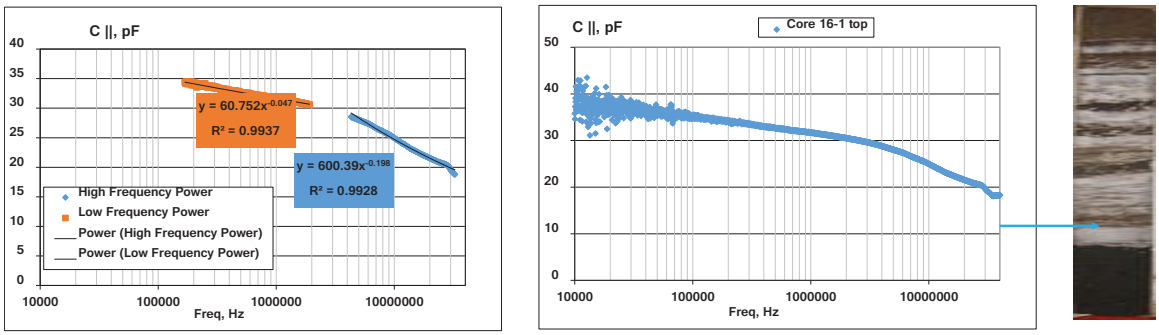

Figure 8: EM sweep and power fit from an inter-bedded shale sample

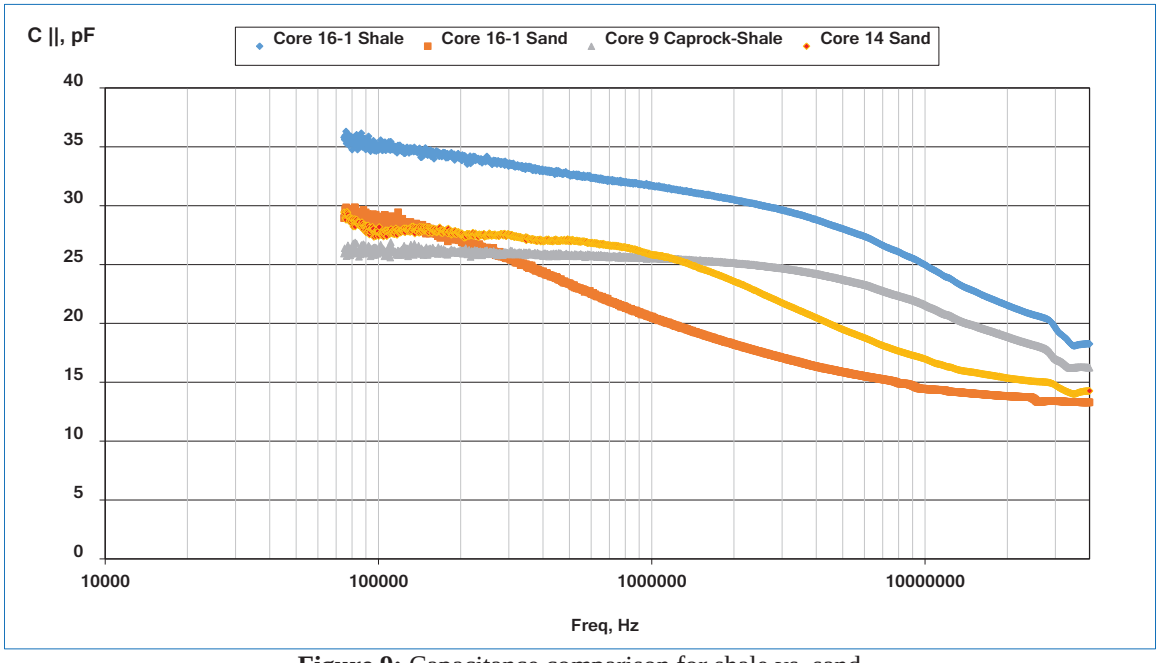

Figure 9: Capacitance comparison for shale vs. sand