MEASUREMENTS OF MOBILE WATER SATURATION IN OIL SANDS

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ABSTRACT
The presence of mobile water saturation in heavy oil and bitumen systems is of considerable importance when understanding how different reservoir recovery methods will work. In non-thermal heavy oil production, the presence of mobile water saturation has extreme significance to the production of cold heavy oil (CHOPS) wells. Some wells are able to produce oil under relatively low and constant water cuts, while other wells produce significant water and quickly need to be shut in due to high production water cuts. In this study, an NMR and core analysis approach is used to shed some light into the properties of oil sand with or without mobile water present. Specifically, tests were run in order to study if mobile water is a localized pore scale phenomenon or if it can be understood through a more macroscopic view of the reservoir.

Samples of core are taken from two heavy oil producing wells: one that experienced very high production water cuts, and the other that produced mainly heavy oil with minimal water. The samples (containing heavy oil and connate water) are flooded with water in order to measure effective permeability to water. NMR spectra are also obtained after flooding and after cleaning of the cores, in order to understand the pore-scale location of water in different effective permeability samples. The outcome of this study is insight into what is the difference in core properties between wells with vs. without mobile water. The key conclusion reached is that wells behave similarly at the pore/core scale, but differences are observed macroscopically. The well with high historical water contains thin zones of high water saturation (high water effective permeability) which were missed at the resolution of the logs. Water production may be due to the presence of these heterogeneous zones.

INTRODUCTION
Cold heavy oil production with sand (CHOPS) is a unique non-thermal reservoir recovery strategy that is applied in many unconsolidated oil reservoirs in Alberta and Saskatchewan. This recovery technique involves providing maximum drawdown to pull oil to production wells, and is based on the concepts of process enhancement through foamy oil flow [1,2] and sand production [3]. During CHOPS production, the high pressure drawdowns lead to the generation of discontinuous gas droplets within the oil phase, which keep the differential pressure high in the system and drive foamy oil to the

production wells. Furthermore, sand production creates regions of high permeability (wormholes) throughout the reservoir, which act as conduits for further production of oil. CHOPS production is run in unconsolidated oil sand reservoirs, where sand permeability is on the order of Darcies and oil viscosity is on the order of 1,000 – 50,000 mPa·s at reservoir temperatures. The high oil viscosity is the biggest challenge to production; if there is mobile water present in these reservoirs, water will tend to flow preferentially to oil. Accordingly, oil production will decline and wells will “water out”. Identifying if a given heavy oil pool has mobile water is very important for assessing the chance of economic success for CHOPS wells drilled into that pool.

This document is a case study of two CHOPS wells from northern Alberta. The oil in these wells is on the order of 30,000 – 50,000 cP at reservoir conditions, and has an *in-situ* solution GOR on the order of 15 m^3/m^3. In the initial identification of oil pay, the determination for production was made on the basis that both wells have porosity > 30% and measured resistivity (R_t) values greater than 10 ohm·m. In terms of production, **Figure 1** shows that Well 1 produced oil under relatively low and constant water cuts, while Well 2 exhibited much higher water production and, despite attempts to control the production, the water cut spiked again and eventually Well 2 was shut in. This historical production was observed despite the fact that the resistivity (indicative of oil saturation) is higher in Well 2 vs. Well 1 (**Figure 2** and Figure **3**). The goal of this study was to investigate if the differences between these wells can be understood on the basis of pore-scale water location within the sand of the two formations, or if the high water production in Well 2 is due to a more macroscopic phenomenon.

EXPERIMENTAL PROCEDURE

The study of pore-scale water location was made through NMR and permeability measurements in oil sand cores. 1” core plug samples are taken from stored frozen full diameter core intervals from the two heavy oil wells (Well 1 and Well 2), and samples are shown in Table **1**. NMR spectra on the initial cores showed that the samples were partially dried out. The samples were vacuum saturated with brine. The effective steady state permeability to water was measured by running brine through the core at low DP/L values, in order to measure water permeability without producing any oil. The NMR of the cores were then re-measured and Dean-Stark was done to measure the connate water present in each vacuum saturated core. The cleaned sand was saturated with water to measure the true pore size distribution of the sand in each core with NMR.

Furthermore, core analysis (Dean-Stark) water saturations were present over the oil-bearing interval in both wells. Based on correlations of water effective permeability vs. water saturation on the tested samples from Table **1**, a macroscopic study was also run to output profiles of predicted effective water permeability as a function of depth (and water saturation) in each well.

RESULTS

Table **1** shows the core samples that were taken from Wells 1 and 2. The Dean-Stark water saturations are measured on the cores after they have been vacuum saturated and water effective permeability has been measured. These permeability values are also listed in **Table 1**. Effective permeability values are low in the core samples with higher oil saturation, which is expected.

Two types of flow behaviour were observed in the tested cores. One flow type is shown in **Figure 4**, which is the spectra from a low oil saturation lean zone in the reservoir. Water vacuum saturated and flooded through the core is in the same T_2 ranges as the actual NMR pore sizes from this sand. In other words, water exists in the core in direct contact with the sand grains, so water flows as a wetting fluid [3,4]. In contrast, **Figure 5** is a sample containing higher oil saturation. In this case, water from saturation and flooding exists mainly as a slow-relaxing peak at longer T_2 values than the true pore sizes for this sample. In oil-rich samples, water injected even at low injection pressures tends to finger through the oil, i.e. viscous forces dominate flow patterns in high oil saturations. These figures demonstrate that there are two different flow types present in oil sand, and the physics of displacement will be different for both flow types. Unfortunately, both wells exhibited this same behaviour for high S_w vs. low S_w samples. While the NMR shows different flow behaviour in oil rich vs. lean zones, this cannot be used to infer microscopic differences between Wells 1 and 2. Furthermore,
Figure **6** shows that both wells have a similar behaviour in terms of effective water permeability vs. water saturation. In other words, the high water production in Well 2 is not a pore-scale difference in wettability or water location within this formation.

A macroscopic view of the wells provides better insight into the production response of the two wells. **Error! Reference source not found.** is the resistivity log (calculated) and core (measured) water saturation profile over the producing zone of this well. The black box at the left of the figure indicates the perforation zone within the oil formation. Water saturations from log and core were used to estimate effective permeability to water by applying the trend line from the core measurements in
Figure **6**. **Error! Reference source not found.** shows that this well has low effective permeability to water: values are generally 10 mD or less, as predicted from the water saturation profile. In contrast, **Error! Reference source not found.** plots the resistivity log (calculated) and core (measured) water saturation profile for Well 2. The log initially provides a tightened water saturation profile with depth, but from the finer resolution core measurements, it is observed that there are thin intervals present in this formation that have much higher water. When water saturations are used to predict effective water permeability, Figure **7** shows core predictions of water permeability that can be in the range of 100 mD or higher in these thin lean streaks. The actual resistivity data (Figure **3**) was noisy, compared to the more gradual resistivity changes in Well 1 (Figure **2**). These changes were initially smoothed out in the log predictions of saturation, but the inclusion of core Dean-Stark data shows that these R_t variations are physically present, and should be included in the calculated water saturation profile for this well. A better

log R_t model is shown that has higher fidelity to the R_t variations measured in this well, and greater variations in the predicted permeability as a direct result of these R_t heterogeneities.

The results of this study can provide insight into the ability of these unconsolidated reservoirs to flow non-thermal oil. With absolute permeability on the order of 100 – 1000 mD and water permeability only around 10 mD, heavy oil can be produced even though its viscosity is so much higher than that of water. As water permeability increases by an order of magnitude the mobility of water is higher than that of oil, and the well will preferentially start to produce water.

CONCLUSION

Water effective permeability at connate water saturations is on the order of 1 – 10 mD in oil rich zones, and can approach 100 mD or higher in lean oil zones. The response of high vs. low water producing CHOPS wells is not due to microscopic (pore level) differences between the wells. Instead, the high water production can be related to local variations in water saturation within the oil zone. Thin streaks of high water saturation can be quite permeable to water, and these zones may be missed from logging tool interpretations. Proper reservoir description requires an understanding of heterogeneities in fluid saturations, either through the collection of core or by ensuring that the well log models have fidelity to the variations in measured R_t in the producing intervals.

ACKNOWLEDGEMENTS

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Well No	Sample	kw (mD)	Dean-Stark post waterflood So (fraction)	Dean-Stark post waterflood Sw (fraction)
1	1	46.4	0.284	0.716
	2	150.9	0.524	0.476
	3	162.4	0.509	0.491
	4	1	0.644	0.356
2	1	2.8	0.516	0.484
	2	1	0.682	0.318
	3	1.4	0.712	0.288
	4	42.7	0.012	0.988
	5	1300	0.058	0.942

Table 1: Core Analysis Samples Tested for NMR and Water Permeability

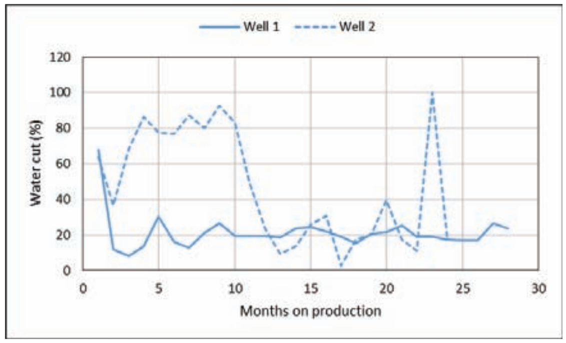

Figure 1: Historical water cuts of Well 1 and Well 2

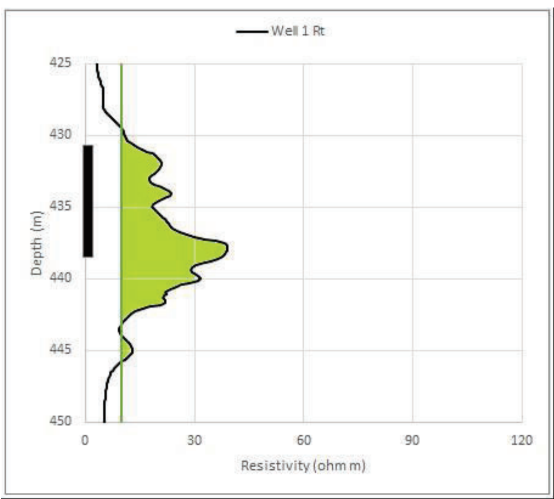

Figure 2: Well 1 Resistivity Profile

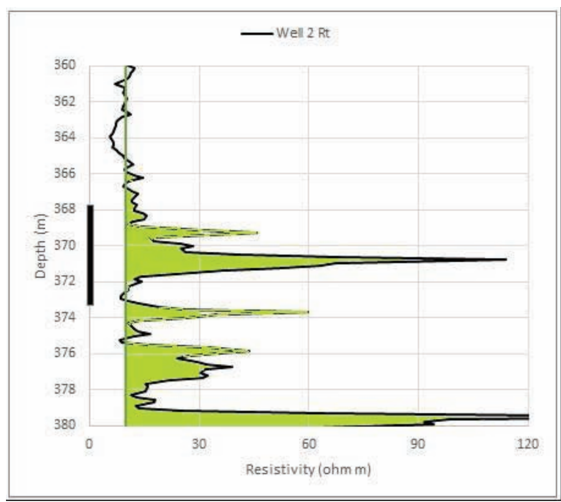

Figure 3: Well 2 Resistivity Profile

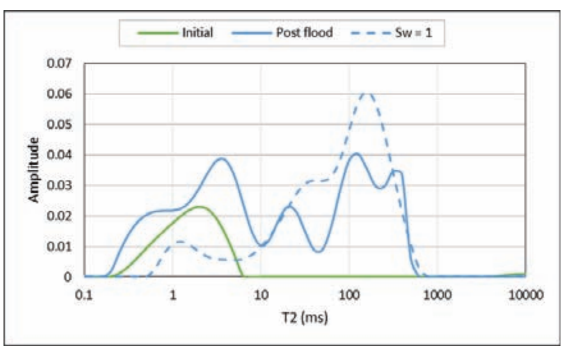

Figure 4: NMR spectra for low oil saturation core

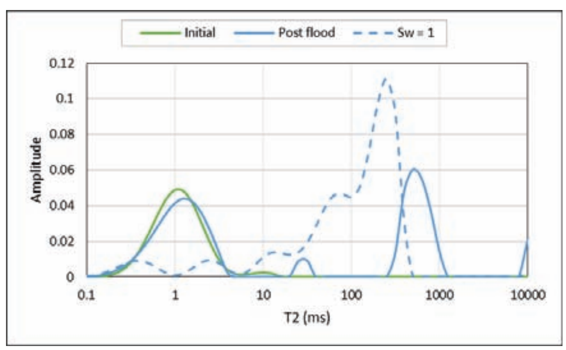

Figure 5: NMR spectra for high oil saturation core

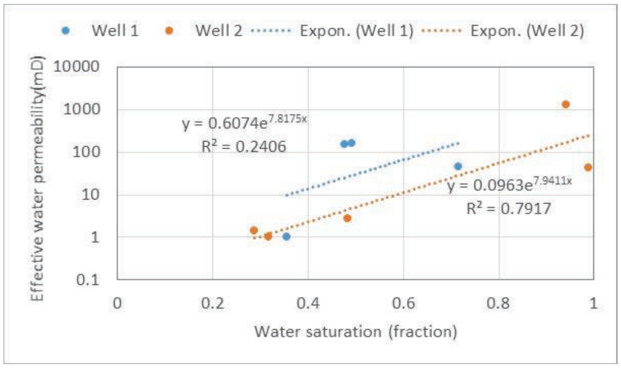

Figure 6: Water effective permeability vs. water saturation

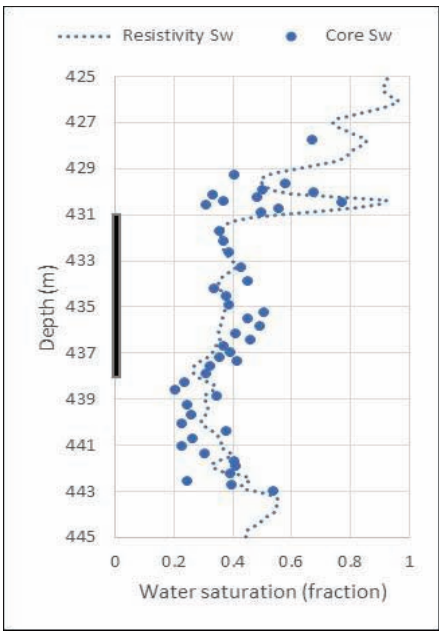

Figure 7: Log and core Sw profile for Well 1

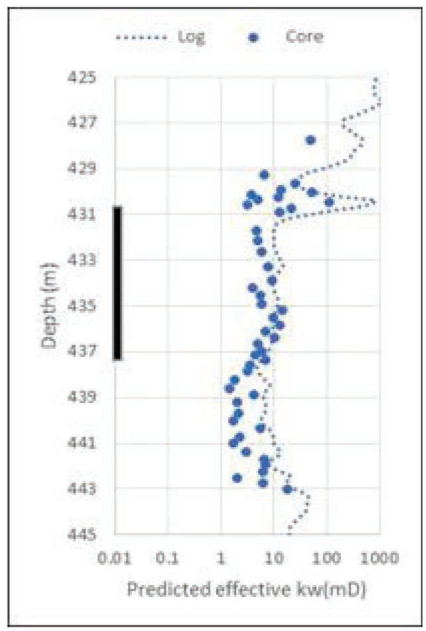

Figure 8: Log and core predictions of effective kw for Well 1

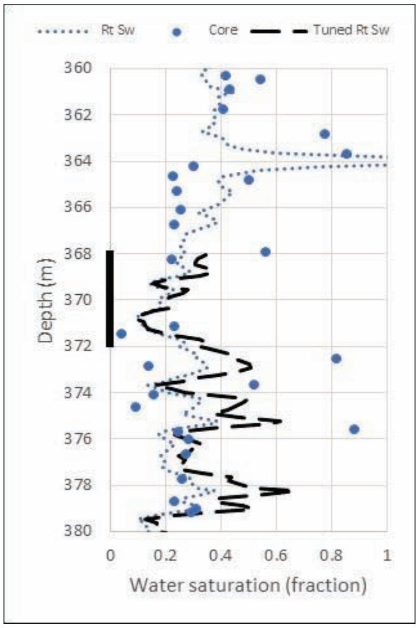

Figure 9: Log and core Sw profile for Well 2

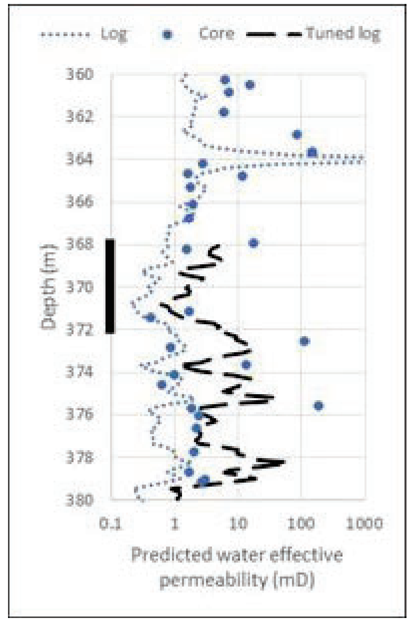

Figure 7: Log and core predictions of effective k_w for Well 2