Unlocking the NMR Potential in Oil Sands

Kevin J. Pyke
Nexen Energy ULC

Abstract

The Lower Cretaceous McMurray Formation in Alberta is the primary bitumen producing horizon in the Long Lake and Kinosis SAGD (Steam Assisted Gravity Drainage) development projects. Conventional log analysis methods used to evaluate this heavy oil reservoir employ a resistivity based water saturation (Sw) equation. These methods are challenged by the vertical and lateral variability in formation water resistivity (Rw) which is often unknown to the log analyst. In order to overcome this limitation, log derived saturations are calibrated to Dean Stark (DS) extraction results. However, not all wells are cored and this leaves a high level of uncertainty in the log calculated Sw in these wells. In addition, the core measured porosities are often found higher than the corresponding wireline density porosity and the validity of core measured saturation becomes questionable.

The Nuclear Magnetic Resonance (NMR) log which is insensitive to water salinity variation provides an alternative to core-calibrated log saturation. The McMurray oil sands environment is favorable to NMR logging due to low borehole fluid invasion, low Gas-Oil-Ratio, high viscosity, low formation temperature and simple sand/shale lithology. Saturation analysis relies on the fact that the NMR T_2 signal of viscous organic matter relaxes and decays rapidly before the downhole instrument performs any measurement, resulting in an apparently low NMR porosity. This porosity deficiency is used to estimate bitumen volume in the reservoir.

In this paper, we present examples, with comparison of log and core results from a Kinosis well, to illustrate the methodology which provides consistent saturation determination that is independent of formation water salinity. Probabilistic uncertainty analysis shows the NMR model provides a reliable estimate of bitumen saturations in clean and moderate shaley sands. However, uncertainty increases with shale content due to overlapping of shale and bitumen T_2 signals, which is a limitation of the model. The producing reservoir in Long lake and Kinosis is relatively clean and the log derived shale volume is generally less than 30%. High confidence in the NMR analysis allows for optimization of the coring program and reduction of field development costs.

Introduction

Athabasca oil sands in northeast Alberta form one of the largest bitumen deposits in the world. The main reserves are contained in the Lower Cretaceous McMurray Formation which is the primary producing horizon in the Long Lake and Kinosis development areas (Fig. 1). The McMurray Formation unconformably overlies the carbonates of the Devonian Beaverhill Lake Group and is, in turn, unconformably overlain by the Wabiskaw member of the Clearwater Formation. The Wabiskaw member is overlain by marine shales and very fine sands of the Clearwater Formation, Grand Rapids Formation and Quaternary Glacial Deposits. A stratigraphic sequence of the formations is shown in Figure 2.

Depositional setting of the McMurray ranges from fluvial to estuarine and shallow marine. In the Kinosis area, the McMurray Formation comprises a lower, fluvial dominated unit (“the continental”), a middle fluvial-estuarine channel complex and a thin upper shoreline deposit (“the A1”). The main reservoir is the middle fluvial-estuarine complex which makes up the majority of thickness of the McMurray Formation. “The Continental” is typically preserved only within lows on the Devonian, slightly coarser grained (medium to coarse sand to rare pebbles) and is almost always wet. The upper “A1 shoreline” unit is thin (1-4 m), mud-rich, and may be saturated with gas, water or bitumen. Neither are reservoir targets. Our main reservoir, the middle McMurray fluvial-estuarine channel complex, was created by multiple episodes of valley incision and subsequent infill with heterogeneous fluvial-estuarine deposits. The resultant stratigraphy is a complex amalgamation of reservoir and non-reservoir deposits. Sediment is comprised of fine grained quartz sand with subordinate amounts of silt and clay laminae, IHS (Inclined Heterolithic Stratification) beds, and breccias of various clast sizes. Most of the reservoir is bitumen-saturated although it can contain bottom water and/or top water and/or top gas. The bitumen portion is characterized by an average effective porosity of 30% and an average effective water saturation of 28%. Effective porosity is defined as the total porosity minus the shale porosity, and the effective water saturation is the fraction of water in effective porosity. The top of the bitumen saturated fluvio-estuarine reservoirs varies from 198 to 316 m above sea level (asl) and the base of the bitumen ranges from 191 to 283 m asl.

The McMurray reservoirs consist of 3 producing facies (clean sand, sandy IHS and breccia) and 3 non reservoirs (muddy IHS, mudplug and mudstone). Typical openhole well logs and core facies over the McMurray reservoir in Kinosis are shown in Figure 3. Formation water salinity varies both vertically and laterally as a result of the complex depositional history and reservoir discontinuity. Examples of formation water salinity variation of Long Lake and Kinosis wells are summarized in Table 1. In Figure 4, the salinity variation is shown by the log resistivity profile. From 240 to 250 m, the resistivity log measurements are much lower compared to that recorded above but the core measured bitumen saturation remains high. This is further supported by the core measured formation water salinity of this well. The SP log can provide an alternative to estimate Rw in wetter zones but it cannot be used reliably in bitumen saturated sands due to inconsistent log responses. In Figure 4 one would expect the SP to show more negative deflection in the saline interval at 245 m compared to the sands above since the clean oil sands exhibit similar porosity and fluid saturation. However, this is not the case.

Petrophysical Model

Conventional saturation analysis, using formation resistivity log, requires a prior knowledge of formation water salinity at each depth level. In oil sands evaluation, this is achieved by calibrating the log derived bitumen content to the Dean Stark measurements. Dean Stark extraction is a laboratory method which is widely used in Oil Sands to measure porosity and fluid saturation in core samples. It is a process whereby a boiling solvent is used to vaporize water and separate bitumen from solid. The weights of oil, water and solid are determined by mass balance. Uncharacteristically high and inconsistent porosities from Dean Stark have been widely reported in the Oil Sands industry. In recent years, over 60% of the core analyses received by Nexen reported higher core measured porosity compared to the wireline density porosity. We have yet to identify the cause(s) of the problem but our experience in Oil Sands indicates the wireline data is reliable and we believe core disturbance during coring (Hu et al, Blanch 2013), improper sample handling and measurement error are partly responsible for the erroneous core data. Since Dean Stark porosity is derived from the core fluid content, validity of the measured saturations becomes questionable. In the absence of reliable core data (i.e. non-cored wells or invalid core data) for log calibration, saturation analysis from logs is problematic.

In 2011 and 2012, the Nuclear Magnetic Resonance (NMR) log, which provides reservoir fluid information independent of formation water salinity, was field tested in 12 Kinosis wells. An example of a NMR log from a core well is presented in Figure 5. NMR application in oil sands to determine bitumen content is a documented technique (Chen et al. 2008, Najia et al. 2002, Bryan et al. 2005). Oil sand environment is favorable to NMR logging as high porosity and low reservoir temperature result in a high signal-to-noise-ratio. Borehole fluid invasion effect is negligible in viscous and non-mobile bitumen zones. In addition the NMR measurement is less effected by salinity variation encountered in our McMurray reservoir. For the salinity range that we are dealing with(<50kppm), the salinity effect is insignificant (simulation shows only about 0.01 change in HI as you go from 0 to 50kppm, at 20% Sw and 35pu total porosity, this is 0.2 x 35 x 0.01=0.07 pu).

Experiments show that bitumen relaxes through bulk relaxation, whether in bulk or in-situ (Bryan et al. 2005), which makes the bitumen signal easy to recognize on the transverse relaxation time (T_2) spectrum. T_2 decreases with increase in oil viscosity and for extreme viscous fluids, such as bitumen (viscosity of Athabasca bitumen can range from several hundred thousand to several million cp), the relaxation times become so short that only a very small fraction of the total signal can be measured by the NMR logging tool. In clean sand, this bitumen signal is clearly defined at T_2 less than 1 ms (Figure 5). In lab based NMR experiments(Bryan et al. 2005), the bitumen peak signal has a clearly defined T_2 signal less than 1ms. The bitumen T_2 is a function of viscosity, however, in our viscosity range, this peak falls well below 1ms. Our method accounts for any bitumen signal up to 4ms, and as such, covers for any possible shift in T_2 due to viscosity change.

The total porosity measured by NMR in bitumen saturated sands represents water and this small fraction of bitumen signal, which could see up to 28% of the total pore volume(see Figure 5a). Comparison of NMR porosity with the density total porosity, which includes all water and bitumen volumes, allows determination of bitumen content in the reservoir.

The T_2 range of the measurable bitumen may overlap with the shale water in shaley sands and the amount of overlap depends on the shale properties and volume encountered. Since the T_2 signal of shale varies between 3 and 4 ms, the measured T_2 in shaley bitumen sands becomes longer and the spectrum will shift to the right crossing the 1 ms clean sand cutoff. Accurate NMR analysis requires separation of the shale and bitumen signals. In gas bearing zones, NMR porosity is under-estimated due to the low hydrogen index of gas and NMR analysis will over-estimate bitumen volume when gas correction is not applied.

NMR Interpretation

The small bitumen volume visible to the NMR tool is determined by summing the porosity volume below a T_2 cut-off of 4 ms and applying a correction for clay bound water which is estimated based on log derived shale volume and porosity. The 4 ms cut-off defines the upper limit of shale signal which appears to work reasonably well in Long Lake and Kinosis. Free and capillary bound water relax with longer T_2 times beyond 4 ms and they do not interfere with the shale correction.
The NMR model does not apply to gas bearing intervals.

Lithology of the McMurray sand consists of sands and shales and simple deterministic methods are used in log analysis. The following equations are applied to calculate porosity, shale volume, bitumen bulk volume and weight:

$$Phi_{total} = \frac{Den_{matrix} - Den_{\log}}{Den_{matrix} - Den_{fluid}} \quad (1);$$

$$I_{gr} = \frac{GR_{\log} - GR_{clean}}{GR_{shale} - GR_{clean}} \quad (2);$$

$$I_{gr} \leq 1.13 \, and \; I_{gr} \geq -2.52 \quad (3);$$

$$Vsh_{Clavier} = 1.7 - \sqrt{3.38 - (I_{gr} + 0.7)^2} \quad (4);$$

$$Vsh_{ND} = \frac{NeuPor_{\log} - DenPor_{\log}}{Neu_{shale} - Den_{shale}} \quad (5);$$

$$Vsh = Min(Vsh_{Clavier}, Vsh_{ND}) \quad (6);$$

$$Weight_{bit} = \frac{Phi_{total} - Vsh * NMRPor_{shale} - NMRPor_{total} + NMRPor_{4ms}}{Den_{matrix} - \left(Den_{matrix} - Den_{fluid}\right) * Phi_{total}} \quad (7);$$

$$Bvo_{bit} = Phi_{total} - Vsh * NMRPor_{shale} - NMRPor_{total} + NMRPor_{4ms} \quad (8);$$

Where:

Phi_{total} is density log total porosity assuming matrix and fluid density of 2.65 and 1.0 g/cc respectively
$Vsh_{Clavier}$ is log derived Gamma Ray shale volume from Clavier model
Vsh_{ND} is log derived shale volume from density and neutron porosity logs
$Weight_{bit}$ is bulk mass fraction of bitumen in wt/wt
Bvo_{bit} is bitumen bulk volume in v/v

Bitumen density has a documented range of 0.96-1.02 g/cc. We have taken density values from over a thousand of produced bitumen samples from all producing wells. The average values from these Long Lake samples have an Absolute density of 1.0123 g/cc.
The other parameters used in the equations are described in detail in Appendix 1.

An example of the interpretation results of a Kinosis well #1 is presented in Figure 6. The well was drilled in 2011 and cores were taken in the McMurray sands. Core porosity and fluid saturation were measured by Dean Stark method and the length of core samples ranges from 20 cm to 30 cm. Quality of the core analyses was evaluated based on porosity comparison between wireline density log and core data. A good porosity agreement is indicative of reliable core data. The density (PHIT), NMR (MPHSC_4MS_COR) and core porosities (PHIT_CORE_DS) are shown in Track 4. The green shaded area between the density and NMR porosities represents bitumen volume. The core measured and NMR derived bitumen content (in bulk mass fraction) are presented in Track 6. In areas where the core and log porosities agree well, the NMR results are good. When the shale volume is high (i.e. shales at 286 m & 298 m), shale correction on the NMR log becomes difficult and inaccurate and the model cannot reliably predict the bitumen saturation. However, the validity of core measurements over these shale intervals is questionable as the porosities are much higher than that of the density log. From 256 to 264 m, the reservoir facies consists of sand and sandy IHS. The vertical resolution of the NMR is about 4 feet and the model is unable to reliably evaluate bitumen saturation in the thinly laminated sand/shale sequence.

Conclusions

A NMR saturation model which evaluates bitumen content of the McMurray sands is established for the Long Lake and Kinosis SAGD areas. The model is insensitive to formation water salinity variation which has been a main uncertainty in resistivity based log analysis. Since 2013, the number of core holes drilled in Long Lake and Kinosis has been reduced by 30% to 40% and NMR log was run in the non-cored wells. Results have been encouraging to date.

Uncertainty analysis of the NMR model shows a high confidence of the log derived bitumen saturation. However as stated previously, the model cannot be reliably used in either gas bearing or very shaley intervals.

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