DEVELOPMENTS IN GAS HYDRATE FORMATION EVALUATION

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ABSTRACT
There has been a dramatic increase in both the amount and type of geophysical well log data acquired in gas hydrate saturated rocks. Data has been acquired in both offshore and Arctic environments; its availability has shed light on the applicability of current tools and the potential usefulness of recently developed and developing technologies.

Some of the more interesting areas of interest are related to the usefulness of nuclear elemental spectroscopy data, the measurement of in-situ permeability and the interpretation of electrical borehole image and borehole seismic data.

A key parameter for reservoir characterization and simulation is formation permeability. A reasonable understanding of this property is key to the development of future gas hydrate production.

Typical applications of borehole image data are an appreciation of a reservoir’s geological environment. In hydrate saturated reservoirs, borehole images can also be used to assist in the understanding of the gas migratory path to the hydrate bearing formation.

Traditionally, the identification of bottom simulation reflections (BSR) on surface seismic surveys has been used as an indicator of hydrates. Lately, the reliability of this as an indicator has been shown to be less than ideal. Recent borehole seismic survey acquisitions have advanced the understanding of this surface seismic response.

This paper presents a review of the current state of geophysical log measurements in hydrate saturated reservoirs, their benefits and limitations.

INTRODUCTION
The importance of the acquisition of key petrophysical parameters like porosity ($\phi$), water saturation ($S_w$), clay volume ($V_{cl}$) and permeability ($k$) is well understood by the exploration and production industry. Derivation of these important parameters from geophysical well log investigations has evolved considerably since Archie first developed his empirical approaches over 60 years ago (Archie, 1942). In certain environments, estimates of these parameters have been reasonably ascertained but for others environmental and geological conditions complicate the measurement and make the derivation of these petrophysical parameters problematic.

In methane hydrate saturated reservoirs, with the use of traditional formation evaluation measurements; it can be difficult to establish accurate values for the petrophysical parameters mentioned above. More recent technologies such as magnetic resonance, nuclear spectroscopy and advanced borehole sonic measurements have vastly improved their derivation and are shedding light on other items of interest to methane hydrate production, providing geoscientists with more accurate reserve estimates and enhanced understanding of production viability.

The following summarizes some of the newer and not so new technologies with a focus on nuclear spectroscopy, magnetic resonance, epithermal neutron and thermal neutron, borehole imaging and borehole sonic, vertical seismic profiling and their applications to open-hole methane hydrate reservoir characterization. Examples are drawn from the JOGMEC/NRCan/Aurora Mallik gas hydrate production research program recently conducted in the Mackenzie Delta and from the 2004 field investigations in the Nankai trough (Murray et al, 2008).

NUCLEAR ELEMENTAL SPECTROSCOPY
An accurate understanding of mineralogy is important in porosity evaluation for matrix density ($\rho_{ma}$), neutron porosity matrix ($\phi_{nma}$), sigma matrix ($\Sigma_{ma}$) and to estimate the clay mineral fraction to correct resistivity-based saturations for the effects of excess clay conductivity.

$V_{cl}$ estimates from traditional clay indicators such as gamma ray, SP and thermal neutron - formation density porosity separation are often misleading. In formations having light hydrocarbons such as gas or condensate, density-neutron logs under-estimate $V_{cl}$ due to light hydrocarbon effects. Also, if realistic values of matrix density and neutron matrix porosity are not known then the computed neutron and density porosities may not
show the signature light hydrocarbon cross-over effect and potential pay can be overlooked (Rasmus et al, 2004). Conversely for methane hydrate reservoirs, the presence of methane hydrate causes a slight increase in both the neutron and density porosities. As for the case of light hydrocarbons this fluid affect needs to be considered when attempting to estimate $V_{cl}$.

With traditional methods, the mineralogy in the hydrate bearing formations in Mallik complicate the estimation of $V_{cl}$. In this environment, nuclear spectroscopy data allows for more precise estimates of $V_{cl}$, $\rho_{ma}$, $\phi_{Nma}$ $\phi_{EpiNma}$ and $\Sigma_{ma}$.

Figure 1 shows the computed nuclear spectroscopy result over hydrate and non-hydrate saturated intervals in a well in Mallik. Track 1 contains the nuclear spectroscopy computed lithology, percent of clay (grey), combination of quartz-feldspar-mica (yellow), carbonate (blue), pyrite (orange) and coal (black). Track2 has the nuclear spectroscopy computed estimates for $\rho_{ma}$, $\phi_{Nma}$ and $\phi_{EpiNma}$ while Track 3 has the computed estimate of $\Sigma_{ma}$. The presence of hydrate cannot be identified from this log as the measurement responds only to reservoir lithology, not to fluid content. However one can observe that the hydrate saturated interval contains less clay than the surrounding zones (Murray et al, 2008).

EPITHERMAL NEUTRON

A combination of formation density and magnetic resonance (MR) measurements, allow estimation of reservoir porosity. In methane hydrate reservoirs it is particularly useful to compute both accurate estimates of porosity ($\phi$) and methane hydrate saturation ($S_{hydrate}$) (Kleinberg et al, 2005) and (Murray et al, 2005a). Similarly, in-situ gas hydrate saturated reservoir porosity and saturation can be estimated from a combination of epithermal neutron and MR log data. The key advantages of estimating gas hydrate reservoir porosity and saturation from the epithermal neutron - MR combination is reduced rugose borehole measurement affects, and in the case of pulsed neutron generator (PNG) tools, the elimination of a nuclear chemical source. Pulsed neutron tools generate neutrons on demand and eliminate the need for an americium beryllium (Am241 Be) chemical source, substantially reducing operational and transportation risk.

Similar to MR measurements, neutron porosity measurements respond primarily to a formation’s hydrogen index. For gas reservoirs the use of a combination of neutron and MR measurements to estimate formation porosity is not practical as both tools respond primarily to formation hydrogen index (HI). In gas saturated reservoirs HI decreases and as such porosity responses of both tools are similar.

In the case of methane hydrate saturated reservoirs neutron porosity measurements show a slight increase as the HI of methane hydrates is 1.05, or slightly greater than water at 1.0. As for the density porosity, the presence of methane hydrate causes the neutron porosity to read slightly higher than that for a 100% water saturated reservoir. Due to gas hydrates relatively fast MR relaxation time, gas hydrate volumes are invisible to MR formation porosity measurements. Hence, in gas hydrate saturated reservoirs, neutron and MR measurements can be combined to accurately quantify reservoir porosity and gas hydrate saturation.

There are additional affects on the thermal neutron measurement due to the presence of thermal neutron absorbers such as boron, chlorine, gadolinium, and formation density. These affects cause the neutron porosity measurement to read higher than formation porosity and need to be considered. In order to account
for these affects an epithermal neutron porosity measurement is advised. The Schlumberger Accelerator Porosity Sonde (APS) tool has an epithermal neutron measurement. It contains a high energy PNG source with detector configurations that minimize neutron absorber and density affects (Scott et al, 1994), (Darling et al, 1997) and (Casu et al, 1996). The accuracy of the porosity and saturation computations is further improved with the acquisition of nuclear elemental spectroscopy data as described previously. Accurate values of $\phi_{EpiNma}$ can be derived from the nuclear spectroscopy measurement.

Figure 2 shows the open-hole logs over the same hydrate and non-hydrate intervals as Figure 1. Track 1 contains the gamma ray (green) and caliper curves. Track 2 has the shallow (green) and deep resistivity (red) curves. Track 3 has the thermal neutron (green), epithermal neutron (blue), formation density (red) and MR porosity (black) while Track 4 has the computed formation volumetrics (Murray et al, 2008).

One can observe the resistivity increase in the presence of hydrates, that all four porosity curves have different values, and that there is a dramatic reduction in MR porosity when hydrate is present. The porosity values presented are corrected for environment conditions, the lithology is assumed to be 100% sandstone. Notice that the epithermal neutron records a similar porosity, but not the same as the density porosity. The thermal neutron for reasons mentioned above records a much higher porosity.

Figure 3 shows the thermal neutron, epithermal neutron and density porosities corrected for lithology effects via inputs from the nuclear spectroscopy log. There is a large reduction in the thermal neutron porosity. Also, as one could expect, the epithermal neutron and formation density porosities are almost identical. This suggests that the combination of lithology corrected epithermal neutron and MR porosity measurements could be used to estimate methane hydrate saturated reservoir porosity and saturation similarly to the density-MR (DMR) approach (Freedman et al, 1998).
Fig. 3 Open-hole logs over hydrate and non-hydrate intervals. Compared to Figure 2 the thermal neutron porosity is dramatically reduced. The epithermal neutron and density porosity values overlay.

METHANE HYDRATE RESERVOIR PERMEABILITY

In-situ values of gas hydrate saturated rock intrinsic permeability are critical input parameters for reservoir characterization, reservoir simulation, the understanding of hydrate production and the determination of the most economic method of production.

Multiple studies have shown that original in-situ intrinsic permeability can be reasonably estimated from a derivation of magnetic resonance log data (Kleinberg et al, 2005) and (Murray et al, 2006).

As hydrate is a near impermeable solid, hydrate reservoirs have the unique property in that their permeability is heavily dependent on hydrate saturation. As hydrate is produced, less hydrate fills the pore space and as such overall reservoir permeability increases. To more fully understand hydrate reservoir behavior with production one needs to characterize the relationship between reservoir intrinsic permeability and hydrate saturation. Laboratory attempts at this characterization have been made with sand samples and synthetically generated hydrate (Minagawa et al, 2005) and (Uchida et al, 2005).

A useful in-situ approach to assist with the understanding of how in-situ permeability may change with hydrate saturation is to establish minimum and maximum intrinsic permeability endpoints. MR can be used to estimate the minimum permeability (Murray et al, 2006) and the geochemical nuclear spectroscopy lithology measurement can be used to estimate the reservoir rock’s maximum permeability for the case of no hydrate ($S_w = 100\%$ and/or $S_{hydrate} = 0\%$) (Herron et al, 1997).

Figure 4 shows the results of this computation on the Mallik well for the interval shown previously. As expected the computed intrinsic permeabilities for both the lithology (black) and MR (red) based approaches are similar in the non-hydrate interval but diverge noticeably in the hydrate saturated rock. The different permeability estimates in the hydrate saturated rock establish the intrinsic permeability upper and lower bounds (Murray et al, 2008).
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BOREHOLE IMAGES

The use of electrical borehole image logs for geological interpretation is well known. In addition to the traditional applications such as structural and sedimentological interpretation, the evidence of fractures and faults from borehole image logs in the presence of hydrate saturated rocks can be used to highlight potential migratory paths. Kleinberg suggested that an accumulation of free gas can open a fracture in sediment above it and would occur when the free gas pressure exceeded the strength of the overlying sediment (Grauls et al., 1998), (Flemings et al., 2003), (Hornbach et al., 2004) and Kleinberg et al., 2006).

When the flux of free gas is substantial, gas conduits could be expected to remain open and move gas significant distances. Hydrate will form rapidly at fracture surfaces, stiffening the channel and allowing gas to flow through it without contacting liquid water. The fracture will propagate upwards as long as the gas pressure remains high enough to overcome the cohesion and the stress normal to the fracture plane (Kleinberg et al., 2006).

It is instructive to review borehole image logs for possible evidence of fractures. Figure 5 contains an image example from the Nankai Trough, offshore Japan. It suggests that a high angle event occurs in the middle of a hydrate saturated zone. This is consistent with the hypothesis that the gas migratory path for some gas hydrate deposits is due to high angle fractures (Murray et al., 2008).

![Borehole image from the Nankai Trough, offshore Japan. High angle event occurring in middle of a hydrate saturated zone. Track 1 has the GR, Track 2 the resistivity and Track 3 the borehole image. Track 4 has the dip angle computation for the sinusoids overlaid on the image displayed in Track 3.](image)

BOREHOLE SONIC

Acoustic borehole measurements have been available to the oilfield since the 1950's. The first measurements were used to convert and/or calibrate surface seismic velocities to depth. Until recently, most of the interpretative and processing techniques were limited to the slowness, time and amplitude domains. Lately, the practice of presenting the data in the slowness versus frequency domain has gained acceptance and has been referred to as sonic dispersion analysis. It is particularly useful for analyzing and interpreting dispersive borehole modes for estimating both near-wellbore and...
far-field formation parameters (Sinha and Zeroug, 1997).

These new approaches were used previously in a hydrate research well off the east coast of Japan. Reservoir far-field stresses were estimated from sonic dipole data, information that is of critical importance to wellbore design and optimal reservoir production (Murray et al, 2005b).

The borehole sonic response in a hydrate saturated interval in Mallik was previously described by Plona (Plona et al, 2005). A complete suite of sonic data was acquired including compressional-wave, Stoneley-wave, and four-component shear-wave with cross-dipole. Plona suggested that the hydrate bearing sandstone had low compressional-wave and shear-wave slownesses (fast sound speeds) and behaved in a homogeneous, isotropic manner. And that in contrast, the water-bearing sandstone section exhibited higher compressional-wave and shear-wave slownesses (slow sound speeds), stress-induced anisotropy, and mechanical damage around the borehole.

The example described by Plona referred to data acquired with a previous generation sonic tool, the Schlumberger dipole shear sonic imager (DSI). The following describes the information obtained in a similar hydrate saturated interval with the more advanced Schlumberger Sonic Scanner tool. The key conclusions are that stress-induced shear anisotropy exists in both the hydrate and non-hydrate saturated intervals and that radial variation of slowness is strongest in the non-hydrate bearing intervals. The Schlumberger Sonic Scanner measurement offers a much improved signal noise ratio (SNR) and thus is better able to measure small amounts of acoustic anisotropy. Figure 6 highlights the recent Sonic Scanner log acquired in Mallik (Murray et al, 2008).

In the non-hydrate saturated zone one can clearly see acoustic anisotropy – large amount of cross-energy, slow shear slowness is noticeably slower than the fast shear. In the hydrate saturated interval the acoustic anisotropy exists but is substantially reduced. This observation appears contradictory to Plona’s description of hydrate saturated intervals being isotropic. This difference is entirely due to differences in measurement accuracy between different generations of borehole sonic tools. Unequal stresses in the cross-sectional plane of the wellbore cause stress-induced anisotropy that exhibits a characteristic dipole dispersion crossover. This stress-induced crossover phenomenon is a result of near-wellbore stress concentrations (Sinha et al, 2002), (Sinha, 1997) and (Sinha and Kostek, 1996).

At low frequencies, the dipole flexural waves probe deep into the formation and sense the far-field stress. The dipole polarization along the maximum stress direction senses the higher stress and has the lower
slowness (fast speed). At higher frequencies, the flexural waves probe the near-wellbore region and are mostly influenced by stress concentrations close to the borehole. In this case, the dipole polarization along the maximum far-field stress direction senses a lower stress and hence has the higher slowness (slow speed) (Plona et al., 2000).

Figures 7a and 7b show the dipole sonic dispersion data for two points from Figure 6; i.) in the hydrate saturated interval and ii.) in the non-hydrate saturated interval.

In the hydrate saturated interval it is clear from the dipole dispersion curves shown in the left hand side of Figure 7a that a small amount of acoustic anisotropy exists and due to cross-over that the source of this anisotropy is unequal horizontal stresses (Sinha and Zeroug, 1997). The right hand side of Figure 7a shows the slowness change as a function of radial depth from the borehole into the formation. This slowness versus radial depth display is also consistent with stress-induced anisotropy. The slownesses are slow near to the wellbore and become faster with increases in radial depth. Also near to the wellbore the fast and slow slownesses cross-over.

Fig. 7a Slowness dispersion and radial slowness curves from hydrate saturated interval depicted in Figure 6.

Figure 7b is taken from the non-hydrate saturated interval. Here, due to the absence of hydrate (which effectively strengthens the rock), the stress induced anisotropy (fast and slow slowness cross-over) is significantly larger.

Fig. 7b Slowness dispersion and radial slowness curves for non-hydrate saturated interval, as depicted in Figure 6.

A clearer picture of radial shear slownesses variation with well depth is shown in Figure 8. Track 2 plots the gamma ray and borehole caliper log. Track 3 the slowness variation with radial depth away from the borehole in the fast shear direction. Track 4, the petrophysical volumetric analysis and Track 5 the slowness variation with radial depth away from the borehole in the slow shear direction. In Tracks 3 and 5 the red shading indicates that the shallow DT-Shear slowness is 25% higher (slower velocity) than the deep. Most probably the sands have undergone mechanical alteration caused by the placement of the well (Sinha and Asvadurov, 2004) and Sinha et al, 2006).

Fig. 8 Slowness Radial Variation Log – The red shading indicates that the shallow depth of investigation DT-Shear is 25 % higher (slower velocity) than the deep (green shading). The sands have become weaker near the well.

BOTTOM SIMULATING REFLECTORS (BSR) CORRELATION TO BOREHOLE LOGS
BSR’s are thought to exist due to free gas layers below gas hydrate stability zones. They are commonly observed on surface seismic in the Nankai Trough but have been difficult to correlate to borehole logs. The acquisition of borehole seismic has proven a useful tool in resolving these apparent discrepancies.

Figure 9 shows the log data for a Nankai Trough well. Track 1 has the resistivity data. Track 2 the dipole sonic shear (blue) and compressional (red) slowness logs. Track 3 has the VSP corridor stack. Overlaid on the sonic logs are the derived VSP interval velocities for the shear XLine (gold), shear InLine (green) and compressional (blue) and compressional. The hydrate interval is easily identified from the resistivity and sonic log data but the free gas zone immediately below the hydrate is not. However the VSP interval compressional velocity and corridor stack easily identifies the free gas zone associated with the BSR (Suzuki et al, 2008).

The difficulty in determining the presence of free gas with conventional borehole logs is due to a combination of fluid invasion, low gas saturation and enlarged borehole conditions.

Shallow marine sediments have relatively high porosity (~40%) and low pressure. In this environment low amounts of gas can have relatively large affects on seismic velocities. Sonic fluid substitution modeling indicates that gas saturations of 1-2% will sufficiently decrease the sonic velocity to a value that is similar to those measured by the borehole seismic survey.

SUMMARY

This paper has demonstrated that many of the state of the art formation evaluation technologies have application to the evaluation of methane hydrate reservoirs.

In traditional oil & gas reservoirs, permeability and geomechanical properties such as stress and compressive strength show gradual changes with production. In gas hydrate reservoirs, changes to the above mentioned properties can be dramatic and seriously impact production. Considering this, improved reservoir monitoring techniques is critical to future economic development and production of gas hydrate reservoirs.

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