ADVANCED FORMATION LOGGING: A CASE STUDY OF REVEALING THE TRUE POTENTIAL OF A GAS RESERVOIR

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ABSTRACT
The economic decision to develop a new field depends heavily on the reservoir quality which, in turn, is based on two factors: the storage capacity and the flow capacity of the reservoir. The former is controlled by the porosity and hydrocarbon saturation and the latter is control by the permeability. This crucial information are computed using sets of logging measurement which is often supported by routine and advanced core analysis data. The process of comparing the log based interpretation with the core results can be time consuming and costly. New developments in logging technology especially in geochemical and dielectric logging are aiming to improve the log derived interpretation and reduce the uncertainties of the evaluation. This paper presents a case study where the integration of the advanced and standard logging tool is used to reveal the true potential of a gas reservoir.

For Chevron in Western Australia the standard formation evaluation is usually based on spectral gamma ray, resistivity, density, neutron, sonic and magnetic resonance logs. This logging suite has been proven successful in determining the reservoir quality in clean gas sand reservoirs. However in new frontier fields the uncertainty becomes larger due to complex mineralogy, the choice of saturation equation, unknown formation salinity and the paucity of SCAL data. In this case study, the standard logging suites does provide a reasonable result, however, the introduction of the geochemical log reveals the existence of iron-rich heavy minerals, which suggests a higher calculated porosity after mineralogy correction. The dielectric log being sensitivity to water permittivity was used to measure the irreducible water volume independent of the inputs needed by a typical conventional water saturation method. In oil base mud environments, the dielectric log can measure the irreducible water in the reservoir as it is not displaced by the oil base filtrate. This advanced formation evaluation shows an increase of 22% gas in place in a particular compartment.

A continuous permeability measurement can usually be inferred by the magnetic resonance log based on the free fluid and bound fluid ratio using the Timur-Coates equation. The bound fluid volume is determined by using a typical T2, 33 ms cutoff. However, the paramagnetic minerals in the formation are known to cause alteration in magnetic resonance relaxation time. In this example, the paramagnetic minerals caused a faster transverse relaxation time, hence a higher bound fluid will be computed if the T2 cutoff is not adjusted. This phenomenon has been a difficult challenge to solve in our industry. A new approach to compute the permeability was tried in this study where the irreducible water computed from the dielectric log was used as the bound fluid. The free fluid was computed by subtracting the total porosity with the dielectric irreducible water. The Timur-Coates permeability using these inputs is more consistent with offset data and confirmed by the mobilities from the formation pressure testing tool. The new approach reveals an almost 300% increase of flow capacity compared to conventional methods in the studied section.

FIELD GEOLOGIC OVERVIEW
The Wheatstone field is located in the Northern Carnarvon Basin, Western Australia within adjacent, north-northeast trending horst blocks comprised of Triassic age sediments capped by Jurassic and Cretaceous sealing shales. It is gas bearing and spans more than 600m of tilted Triassic age stratigraphy. Reservoirs generally exhibit excellent properties, with permeabilities ranging up to several Darcies and porosities between 18 and 27%.

Three clastic reservoir intervals are typical of fields in this region: Mungaroo Fluvials, Mungaroo Deltaics and Brigadier Shallow Marine deposits (Figure 1).

The Late Triassic marine Brigadier Formation overlies the Mungaroo Formation. It is composed of alternating sand and shale beds whose thickness range from centimeters to decimeters. The beds are laterally continuous but the unit as a whole has low vertical permeability. There is evidence in the Upper Mungaroo and Lower Brigadier of a transition from a deltaic
environment to marginal marine, upper to lower shoreface, environment. These laminated sequence are not resolvable on seismic.

FORMATION EVALUATION OBJECTIVE

Whilst the fluvial Mungaroo reservoirs are fairly straightforward to evaluate from a petrophysical point of view, the same cannot be said of the Brigadier reservoirs due to presence of thin beds coupled with complex minerals that affects the logs. This case study focusses on the challenges in this formation.

Legacy petrophysical interpretations through the Brigadier Formation typically relied on the traditional GR, Neutron and Density logs. Utilization of advanced, higher-resolution logs in the wireline program for the development drilling campaign enabled more sophisticated and accurate workflows for determining key reservoir properties including reservoir net to gross, porosity and permeability that provide a better match to core data.

Obtaining a better understanding the Brigadier formation has been a key objective of more recent data acquisition program. Improved characterization of the Brigadier Formation not only has significant volumetric implications, but also underpinned operational decisions during drilling, as the decision to complete or abandon a well was based on the interpreted cumulative permeability thickness or flow capacity (kH), if the penetrated section did not meet the necessary kH it would be abandoned and a different orientation would be drilled. High quality interpretations were achieved through acquisition of advanced logs including mineral spectroscopy, dielectric and image logs. In addition, a newer method of evaluation using a multi mineral solver interpretation method improved the understanding of the Brigadier formation by identifying a rapidly varying grain density across the reservoir due to the presence of iron-rich minerals.

Log data acquired in the pilot holes provided interpretations of cumulative kH that formed a major component of the well deliverability estimates. These cumulative kH interpretations were made within a few hours of drilling that helped decisions on whether to keep or side-track the well, and to provide TD estimates for the production holes. While drilling the production holes, only real time LWD data is available, consequently the acquisition programme is focused to gather essential data for making reliable petrophysical interpretations in real-time for TD decisions. Understanding the effects and limitations of real time LWD data in thin beds and high angled wells (~50-60 degrees) is crucial in estimating permeability and net pay.

APPLICATION OF kH

A reservoir acceptance criteria was generated based on achieving an initial predicted well deliverability within adopted screen flux and reservoir drawdown constraints. Using the petrophysical interpretation, a nominal development well completion interval was picked based on maximising reservoir inflow while preserving stand-off between the toe of the completion and the free water level.

Reservoir inflow modelling was undertaken using the log derived permeability profile along the proposed completion length. The open-hole gravel pack (OHGP) screen flux profile at initial reservoir pressure was then calculated as a function of total flow rate to reflect inflow heterogeneity along the planned completion interval. Results were measured against adopted peak flux limits to assess whether or not well deliverability would be expected to be flux limited at initial conditions.

A probabilistic estimate of drawdown limited well deliverability at initial conditions used ranges of average permeability along the proposed completion, combined with net pay and skin (mechanical and non-Darcy) ranges.

Development wells are drilled to either twin an existing appraisal well or drilled next to a dedicated pilot hole. Net pay ranges reflected both structural uncertainty between the pilot or twinned well and the planned producer along with uncertainty in the final reservoir penetration angle of the development hole section.

FORMATION EVALUATION CHALLENGES

The main formation evaluation challenge in the study area is the Brigadier formation where high iron contents in the form of siderite and pyrites are observed in the core data (Table 1). The main mineralogy is quartz with less than 10% of clay and around 5% K-Feldspar. The porosity is between 20 to 27%. A small presence of iron mineral increases the grain density significantly from a typical 2.65 gm/cc of clean sandstone. Solving the mineralogy composition using conventional logs is quite difficult considering the similarity of clay and iron mineral effects to the density-neutron log response. Additional log data is needed to overcome this challenge.

The Density-Magnetic Resonance (DMRP) method (Freedman et al, 1998) is commonly used to obtain robust gas-corrected porosity and permeability in gas sandstone reservoir. The method is based on the simultaneous solution of the petrophysical responses for
the formation bulk density and NMR measurements, i.e:

\[ \rho_b = \rho_{ma}(1 - \phi) + \rho_f \cdot \phi \cdot (1 - S_{g,xo}) + \rho_g \cdot \phi \cdot S_{g,xo} \]  

\[ TCMR = \phi \cdot S_{g,xo} \cdot (HI)_g \cdot P_g + \phi \cdot (1 - S_{g,xo}) \cdot (HI)_f \]  

Where:
- \( \rho_b \) = measured formation bulk density (g/cc)
- \( \rho_{ma} \) = formation matrix density (g/cc)
- \( \rho_f \) = flushed zone liquid phase density (g/cc)
- \( \rho_g \) = gas density at reservoir condition (g/cc)
- \( \phi \) = total formation porosity (v/v)
- \( (HI)_g \) = Hydrogen Index of gas at reservoir condition
- \( (HI)_f \) = Hydrogen Index of liquid phase
- \( S_{g,xo} \) = flushed zone gas saturation
- \( P_g = 1 - \exp\left(-\frac{W}{T_{1,g}}\right) \) = gas polarization function
- \( W \) = wait time of magnetic resonance pulse sequence
- \( T_{1,g} \) = gas longitudinal relaxation time

The simultaneous solution of those two equations for the gas-corrected total porosity is given in the following equation:

\[ \phi_{DMRP} = \frac{DPHI \cdot \left(1 - \frac{(HI)_g \cdot P_g}{(HI)_f}\right) + \lambda \cdot TCMR}{\left(1 - \frac{(HI)_g \cdot P_g}{(HI)_f}\right) + \lambda} \]  

Where:
- \( \lambda = \frac{\rho_f - \rho_g}{\rho_{ma} - \rho_f} \)  

And DPHI (Density derived porosity):

\[ DPHI = \frac{\rho_b - \rho_{ma}}{\rho_f - \rho_{ma}} \]  

Once the corrected total gas porosity is obtained, the corrected magnetic resonance permeability can be computed using the gas-corrected porosity in the Timur-Coates equation as follows:

\[ K_{tim,DMRP} = A \cdot 10^4 \cdot \phi_{DMRP}^B \left(\frac{\phi_{DMRP} - \phi_{BF}}{\phi_{BF}}\right)^C \]  

Where:
- \( K_{tim,DMRP} \) = KTIM, gas-corrected permeability (mD)
- \( \phi_{DMRP} \) = gas-corrected magnetic resonance porosity
- \( \phi_{BF} \) = Bound fluid porosity using T2 cutoff
- \( A = KTIM \) permeability multiplier
- \( B = KTIM \) porosity exponent
- \( C = KTIM \) porosity ratio exponent

The DMRP method gives good results in clean sandstone reservoirs but is expected to be inaccurate in iron-rich sandstone reservoirs. This is due to a combination of; the formation matrix density uncertainty which causes underestimation of the porosity and the T2 cutoff shift from the presence of iron which causes overestimation of irreducible water volume if the standard 33 ms cutoff is used. This will result in an underestimation of permeability.

One of the inputs to compute the DMRP gas-corrected porosity is the density-derived porosity (eq 3), this requires accurate formation matrix density data. Unfortunately, it is difficult to calculate the mineralogy composition from conventional logs for the aforementioned reasons. In most cases, the matrix density is assumed to be 2.65 gm/cc. Figure 3 shows the percentage of porosity error in this assumption if the actual formation density happens to be 2.70 or 2.75 gm/cc. A significant percentage error can be seen in low porosity reservoirs. However, based on the core data in Table 1, the error in this case study is expected to be around 10 to 20%. Additional data from geochemical logs will be able to overcome this issue by resolving the mineral composition in the matrix.

The effect of iron minerals on magnetic resonance T2 relaxation time was studied and reported in the past (Dodge et al, 1995, Rueslatten et al, 1998, Zhang et al, 1998). The high magnetic susceptibility of iron provides a stronger surface and diffusion relaxation, hence increased T2 relaxation rate. Errors in irreducible water volume based on the standard T2 cutoff in iron-rich sandstone is confirmed by laboratory NMR measurements and drainage capillary pressure measurements. Lowering the T2 cutoff is the only way to obtain the correct irreducible water volume, however it is difficult to quantify a variable T2 cutoff using the conventional logs. Multifrequency dielectric dispersion logs were reported to be capable of obtaining irreducible water volume in gas reservoirs drilled with oil base mud (Bean et al, 2013). Combining the dielectric log’s water volume and the corrected total porosity using Timur-Coates permeability equation will provide more robust permeability estimates.
GEOCHEMICAL LOGGING FOR BETTER POROSITY COMPUTATION

Geochemical logging for petrophysical application was introduced over 30 years ago. The tool designs evolved from a pulsed-neutron generator (PNG) and a thallium-doped sodium iodide (NaI(Tl)) scintillator detectors (Hertzog, 1980), to tools based on gadolinium oxyorthosilicate (GSO) (Scott et al, 1991), and bismuth germanate (BGO) (Herron and Herron, 1996). Similar technology with NaI detectors is also available in logging while drilling (LWD) environments (Weller et al, 2005).

The most recent development in geochemical tools utilizes a deuterium-tritium PNG and a large cerium-doped lanthanum bromide (LaBr3: Ce) gamma ray detector which has high-temperature performance and high spectral resolution (Radtke, et al., 2012). The PNG inside the tool emits high energy neutrons (14-MeV) which interact with the atoms in the surrounding formation and induces the emission of gamma rays via inelastic scattering and thermal neutron capture interactions. The resultant overall gamma ray spectrum is then deconstructed into elemental yields based on the characteristic standard spectrum of each element. By definition, the elemental yields are “relative” in that the sum of either the capture or the inelastic yields for each spectrum is separately equal to unity. Elemental yields are a function of the volumetric proportion of an element in the measurement region, as well as the sensitivity of the tool to each element. These yields are the starting point for determining quantitative elemental concentration and mineralogical volumes.

The conversion of relative spectral yields from neutron capture into absolute elemental concentrations in term of dry weight elements is accomplished via a modified geochemical oxide closure model (Grau and Scheitzer, 1989; grau et al., 1989). The dry weight elements are used as the inputs into a multi-mineral solver together along with conventional density-neutron logs to compute the mineralogy fractions and the corrected porosity. This approach can achieve a better porosity value in iron-rich sand reservoirs. Figure 4 shows the data flow from the geochemical log measurement to the final interpretation result.

DIELECTRIC LOGGING FOR IRREDUCIBLE WATER VOLUME AND PERMEABILITY COMPUTATION

The first dielectric logging was introduced in the late 1970’s (Calvert et al., 1977) as single frequency measurements to measure water-filled porosity independent of resistivity logs especially in thin bed reservoir. The interest in this technology declined by early 1990s because of wellbore environment problems such as borehole rugosity and that caused inconsistencies in the measurements.

A new generation of dielectric tool was introduced in 2007 and has several features designed to overcome the shortcomings of previous tools (Hizem et al., 2008). The tool has a new antenna array with collocated transverse and longitudinal transmitters and receivers in a fully articulated pad that is run in contact with the borehole wall, thus avoiding many of the environmental effects that plagued the first generation tool. The new tool operates at multiple frequencies from approximately 20 MHz to 1 GHz, allowing evaluation of dielectric dispersion, i.e. the change in dielectric properties as a function of frequency. Analysis of dielectric dispersion enables the separation and quantification of different effects influencing the dielectric measurement, such as water volume, water salinity and rock texture. It also allows for reconstruction of resistivity at the direct current limit, equivalent to extrapolating the dispersion to zero frequency.

The ability of the tool in OBM environments to measure accurate irreducible water volume of gas sandstone reservoir located far enough up-dip from a gas-water contact has been tested against Dean-Stark core plug measurements and magnetic resonance logs (Bean et al., 2013). This measurement is independent of resistivity logs and the T2 relaxation cutoff. However, the data processing requires accurate total porosity and matrix permittivity inputs, hence running the tool with geochemical tool is an advantage and highly recommended. In this case study, the effect of iron-rich minerals on magnetic resonance make the determination of irreducible water volume quite challenging without adjusting the T2 cutoff. The dielectric tool was thus run to overcome this issue.

The Timur-Coates permeability equation (eq. 6) requires total porosity and bound fluid inputs. An improved total porosity can be achieved by utilizing geochemical logs. The combination with accurate bound fluid measured by dielectric log will give a better estimation of the formation permeability. Equation 6 can be re-written as:

\[ K_{TIM} = A.10^4 \cdot \phi_T^B \left( \frac{\phi_T - PWXO}{PWXO} \right)^C \]  

(7)

Where:

\[ K_{TIM} = \text{Timur-Coates Permeability} \]
\[ \phi_T = \text{Total porosity} \]
\[ PWXO = \text{Water porosity from dielectric log} \]
\[ A = \text{KTIM permeability multiplier} \]
\[ B = \text{KTIM porosity exponent} \]
\[ C = \text{KTIM porosity ratio exponent} \]

The resultant computed permeability compares very favorably with the mobility values from formation testing. In turn, we can relate these improved permeability estimates to core by leveraging the historically good match of mobility values to core permeability measurements (Fig. 5).

WORKFLOW

The following workflow was employed to determine well deliverability.
- Wireline geochemical data was used to derive porosity with the mineral-based evaluation. The multi-mineral solver model calculates the abundance of heavy minerals resulting in a higher average porosity and improved calibration to core data in the appraisal wells.
- The next step was to use this porosity with the dielectric data water porosity (PWXO) to derive permeability using Equation 7. Permeability was validated using mobility data from the formation tester tool. A high sample density mobility profile was obtained in the Pilot wells which proved to be very beneficial in the validation process.
- The net reservoir was derived using high resolution neutron/density logs as well as image logs.

CONVENTIONAL LOG EVALUATION

Figure 6 shows typical conventional logs across a package of gas sand. Density Magnetic Resonance Porosity (DMRP) processing is used to calculate gas-corrected porosity (track 5) and gas-corrected permeability (track 7). All the logs seem to converge to the same conclusion that the reservoir is fining upward with poorer quality reservoir towards the top of the section. The flow capacity and the predicted flow profile predominantly come from the bottom part of the sand package and there is no significant contribution from the upper portion of the reservoir. The computed hydrocarbon porosity thickness and kH using the conventional logs only are given in Table 2.

ADVANCED FORMATION EVALUATION

Figure 7 shows the advanced log data set. The neutron induced gamma ray spectroscopy tool indicates iron content increases towards the top of the interval, hence increasing the matrix grain density (track 5). Once corrected for the mineralogy, the computed porosity is higher than conventional method. This increased iron content also relates to an increase in the surface relaxation in the formation and hence a faster magnetic resonance decay. A higher magnetic resonance of the bound fluid volume is expected if the standard 33 ms cutoff is used. The irreducible water measured by the Dielectric Scanner (PWXO_ADT) is not affected by iron content and is smaller than the BFV (track 7). The new data shows significant increase of gas volumes especially in the iron-rich interval (tracks 7 and 8).

The combination of higher total porosity and the Dielectric Scanner’s irreducible water measurement (PWXO_ADT) can be used to estimate the formation permeability using Timor-Coates permeability equation (eq. 7). The free fluid volume can be calculated by subtracting the PWXO_ADT from the total porosity. The new permeability from the ADT is almost one order of magnitude higher in the iron-rich zone as compared to DMRP permeability (track 9). Based on regional knowledge of mobility data and its established proxy to permeability (Fig. 5), the formation mobility measured by the formation pressure testing tool confirms the higher permeability in this zone. The new flow profile shows significant contribution from the upper zone which was previously under estimated by conventional log data. An almost three fold of initial gas flow capacity is expected in this particular sand package (track 10).

RESULTS AND CONCLUSIONS

Advanced formation evaluation, integrating geochemical and dielectric logs, results in more robust estimates of reservoir quality in the iron-rich gas sand reservoir of the Wheatstone field. Geochemical logs provide significant additional value in obtaining an accurate matrix density and gas-corrected porosity. New generation dielectric logs provide an independent irreducible water porosity that further strengthens the interpretation. Computed Timur-Coates permeability values using these inputs is more reliable compared to formation tester mobility data. This encouraging result has provided Chevron with a significant input for optimizing placement and expected results from production wells.

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REFERENCES


Shell in Malaysia, moving from IT to Project Management and then to Petrophysics, with a short broadening in HR. After stints in Aberdeen, Malaysia and Perth with Shell, he joined Chevron, Perth in 2012.

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**Keith Boyle** is the Petrophysics Team Lead for the Chevron Australian Business Unit. After graduating with a Bachelor of Electrical Engineering from Carleton University in Ottawa in 1981, he worked for Schlumberger as a field engineer, until joining Shell Canada in 1985. The next 30 years were spent working with several operators in various locations until arriving in Perth with Chevron in 2010.

**Djisran Kho** is the Principal Petrophysicist working as Petrophysics Domain Champion for Schlumberger, overseeing the wireline logging operation in the Western Australia region. He received his engineering degree (Hons) from Bandung Institute of Technology and joined Schlumberger as wireline field engineer in 1994. He was assigned in different countries in the Far East and the Middle East of Asia, before attending Schlumberger Log Analyst Training in Houston in 2000. He has held several positions including marketing staff, senior petrophysicist, technical team leader, and project manager. He was the formation evaluation advisor for Schlumberger-KOC North Kuwait Jurassic Gas Development project before moving to Perth.
Figure 1: Stratigraphic column for the study area

Figure 2: Seismic data cannot resolve the zone of interest

Figure 3: Porosity error caused by incorrect grain density assumptions. The highlighted area is the porosity range of interest in the studied reservoir.
Figure 4: Multi mineral solver: data flow

Figure 5: Comparison of core permeability vs formation test mobility values
Figure 6: Conventional log analysis showing degrading reservoir quality upwards.

Figure 7: Advanced logs from spectroscopy shows increased iron content upwards causing increased magnetic resonance irreducible water volume. Dielectric log water volume shows better reservoir quality than conventional logs. Permeability estimates derived from combining the dielectric’s water volume and matrix corrected porosity is higher than DMRP permeability and is confirmed by formation tester measurements.
Table 1: XRD data from a nearby well showing the presence of siderite and pyrite.

<table>
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<tr>
<th>Porosity v/v</th>
<th>Grain Density gr/cc</th>
<th>Quartz % Weight</th>
<th>K-Feldspar % Weight</th>
<th>Siderite % Weight</th>
<th>Pyrite % Weight</th>
<th>Hematite % Weight</th>
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Table 2: Result comparison between conventional data and advanced data showing an increase of 22% hydrocarbon porosity thickness and 295% of expected flow capacity.