Uncertainty in Well Log Analyses and Petrophysical Interpretations

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Abstract

Petrophysical analysis plays an important role in a reservoir study as it provides primary input data for characterization of subsurface formations and evaluation of resources. Common petrophysical input data to a reservoir study include porosity, water saturation, permeability and mineral or rock volumes. These reservoir variables are typically not directly measured by well logging tools; instead, they are usually derived through multiple processes, including acquisition, processing, interpretation and calibration. As each of these steps involves uncertainty, the resultant petrophysical data will have uncertainty and limitations. Uncertainties from well log and petrophysical interpretations should be analyzed, quantified and explicitly communicated to the integration team in order to be accounted for in reservoir characterization and modeling.

Introduction

Petrophysical analysis is critical in a reservoir study; it provides a primary source of input data for reservoir characterization and modeling. Wireline logs provide continuous recordings over the rock formations and give geoscientists insights on the rock properties. These measurements supply critical information for both single-well formation evaluations and field-wide subsurface resource evaluations. It is, however, important to understand that logging data has uncertainties and limitations that, if not accounted for, can lead to an incorrect picture of the area around the wellbore and ultimately of the reservoir.

Reasons for uncertainties

First of all measurements have uncertainties. Second, most logging tools do not provide direct measurements of the petrophysical properties that are used in reservoir modeling and hydrocarbon evaluation. For example, the two most important petrophysical properties in characterizing the in-place hydrocarbon resource are porosity and fluid saturation. They are not directly measured but rather are derived from the acquired logs using transforms based on theoretical and empirical relationships.

Most petrophysical properties used in integrated studies are obtained through a multiple-step process, including data acquisition, processing, calibration and interpretation (Dewan, 1983; Theys, 1999). Each of these processes has uncertainties that affect the results of a petrophysical analysis. Most well logs include basic corrections for the known systematic errors through tool calibrations and environmental corrections. Due to the statistical nature of most measurements and the complexity of the borehole environment some uncertainty will remain, especially as the applied corrections cannot completely eliminate all the errors or cannot be quantified as doing so.

Acquisition problems in wireline logging, such as total or partial tool failure, bad borehole conditions, and poor choices of logging suites, either because of the tool availability or acquisition costs, can affect logging runs and cause uncertainties in the logging data. In a broad sense, different vintages of well logs can be considered as acquisition uncertainties because the different vintages imply different tools that generally have vastly different resolutions and sensitivities, such as sensitivity to environmental factors. This is especially important in studying a reservoir with older log suites. The differences often cause a dilemma when integrating modern and old logs. On one hand, old logs may provide valuable information since they represent the reservoir properties at or close to the initial conditions. On the other hand, quality and sensitivities of old logging tools may be questionable and require extra processing to extract appropriate data. Documentation needed to make a correct analysis may be missing or expertise in analyzing older logs may be lacking. Too often older logs are either completely ignored or used without thorough analyses. While the analyst should never ignore the "value of information", careless uses of older logs can lead to large errors in evaluating formation parameters. Even after careful analyses, integration of data acquired by diverse tools can still convey significant uncertainties. The analyst has to put thought and much effort into merging the old log analysis with the modern log analysis to produce a consistent reservoir picture.

Uncertainties in Petrophysical calculation

A. Sonic porosity

Wyllie time average equation (Wyllie et al., 1958) to calculate sonic derived porosity is as follows –

$$\Phi s = (\Delta t\log - \Delta t\mathrm{ma})/ (\Delta t\mathrm{fl}-\Delta t\mathrm{ma}) \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

Where Φs = sonic derived porosity, Δtlog = interval transit time in formation (log reading), Δtma = interval transit time in matrix, Δtfl = interval transit time in the fluid in formation (freshwater mud = 189 µsec/ft; saltwater mud = 185 µsec/ft)

The interval transit time (Δt) depends on both lithology and porosity. Therefore a formation's matrix interval transit time must be known to derive sonic porosity. Wyllie suggests in sandstone Δtma varies in between 51 and 55.5 µsec/ft. Now

considering formation fluid to be freshwater mud (Δtfl= 189 µsec/ft) and using Δtma = 51 and 55.5 in Eq. 1, the output sonic porosity (Figure 1) shows a difference of 2.26-2.73% in porosity calculation (Table 1).

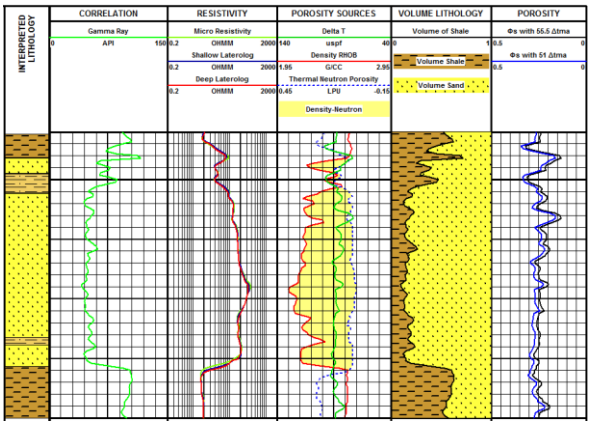

Figure 1. Sonic porosity calculated from Eq. 1 with different Δtma, Output taken from GEOSUITE software by Geologix

Depth Meters	Φs with 55.5 Δtma	Φs with 51.0 Δtma	% Difference
1300	0.3054	0.328	2.26
1314	0.1635	0.1908	2.73
1330	0.1949	0.2212	2.63
1366	0.2419	0.2667	2.48
1380	0.269	0.2928	2.38

Table 1. Sonic porosity calculated from Eq. 1

The change in calculated sonic porosity with different Δtma may seem too negligible and under tolerance limit, but uncertainty is there to pick right value of constants used in the equation, which is here Δtma and Δtfl. Wyllie et al. (1958) formula for calculating sonic porosity can be used in consolidated sandstones and carbonates with intergranular porosity (grainstones) or intercrystalline porosity (sucrosic dolomites). However when sonic porosities of carbonate with vugs or fractures are calculated by Wyllie's formula, porosity values come very low. This happens because sonic logs only record matrix porosity rather than secondary porosities caused by vugs and fractures. If the formation is unconsolidated sand, an empirical compaction factor (Cp) should be added (Asquith and Krygowski, 2004) to Wyllie's equation –

$$\Phi s = (\Delta t\log - \Delta t\text{ma})/ (\Delta t\text{fl}-\Delta t\text{ma})*Cp \quad \ldots\ldots\ldots\ldots\ldots (2)$$

The compaction factor is obtained by-

$$Cp = (\Delta t\text{sh} *C)/ 100 \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (3)$$

Where Δtsh = interval transit time in a shale adjacent to the formation of interest, C = a constant which is normally 1.0 (Hilchie, 1978)

Considering formation fluid to be freshwater mud (Δtfl= 189 µsec/ft) and using Δtma = 51 and 55.5 in Eq. 2, the output sonic porosity (Figure 2) shows a difference of 2.29-2.62% in porosity calculation (Table 2).

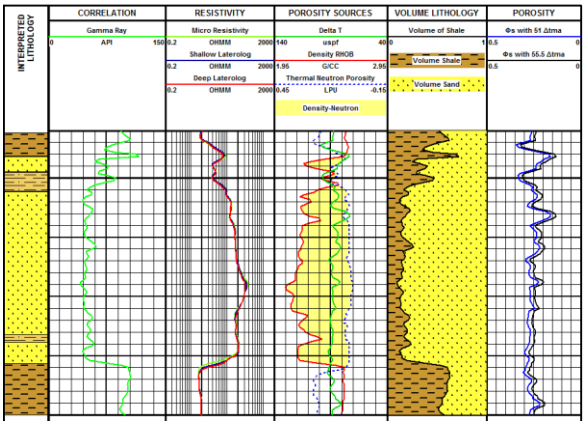

Figure 2. Sonic porosity calculated from Eq. 2 with different Δtma, Output taken from GEOSUITE software by Geologix

Depth Meters	Φs with 51.0 Δtma	Φs with 55.5 Δtma	% Difference
1301	0.3212	0.2983	2.29
1310	0.2651	0.2403	2.48
1323	0.2335	0.2076	2.59
1344	0.2226	0.1964	2.62
1375	0.2854	0.2613	2.41

Table 2. Sonic porosity calculated from Eq. 2

Enlarged borehole, formation fracture, gas in borehole or formation, or improper centralization can produce signal attenuation resulting in "cycle skipping", or DT spikes to higher values. Improper centralization, the lack of standoff, or excessive logging speed can result in "road noise" or DT spikes to either higher or lower values.

B. Density porosity

Density porosity is calculated as –

$$\Phi_D = (\rho\text{ma}- \rho\text{b})/ (\rho\text{ma}-\rho\text{fl}) \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (4)$$

Where Φ_D = density derived porosity, ρma = matrix density ρb = formation bulk density (log reading), ρfl = fluid density (fresh water = 1gm/cc, salt water = 1.15 gm/cc)

Wellsite geologist or logging unit engineer decides the values of matrix density and fluid density to be used. If the formation's actual matrix density is less than the matrix density used to calculate the porosity [i.e. calculating sandstone porosity (ρma = 2.64 gm/cc) using a limestone matrix density (ρma = 2.71 gm/cc)], the log shows a porosity that is higher than the actual porosity (Figure 3).

Using ρma as 2.64 and 2.71 gm/cc in Eq. 4, the output density porosity (Figure 3) shows a difference of 2.62-3.92% in porosity calculation (Table 3).

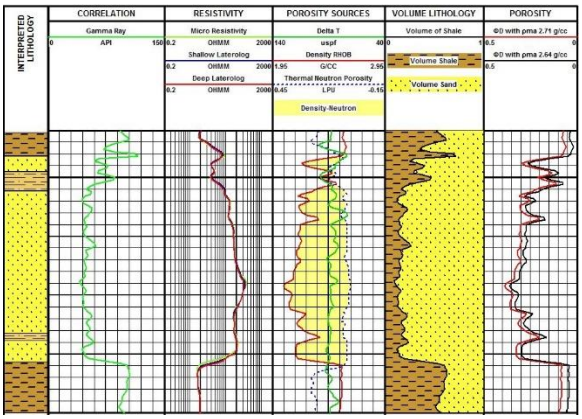

Figure 3. Density porosity calculated from Eq. 4 with different ρma, Output taken from GEOSUITE software by Geologix

Depth Meters	ΦD with ρma 2.71 g/cc	ΦD with ρma 2.64 g/cc	% Difference
1300	0.2105	0.1768	3.37
1330	0.3041	0.2744	2.97
1346	0.386	0.3598	2.62
1368	0.1988	0.1646	3.42
1380	0.0819	0.0427	3.92

Table 3. Density porosity calculated with different ρma

Similar problem comes in when putting fluid density in Eq. 4. Using ρma as 2.64 gm/cc and ρfl as 1.0 and 1.1 gm/cc in Eq. 4, the output density porosity (Figure 4) shows a difference of 0.28-2.13% in porosity calculation (Table 4). So the choice of fluid density can yield uncertainties in calculating density porosity.

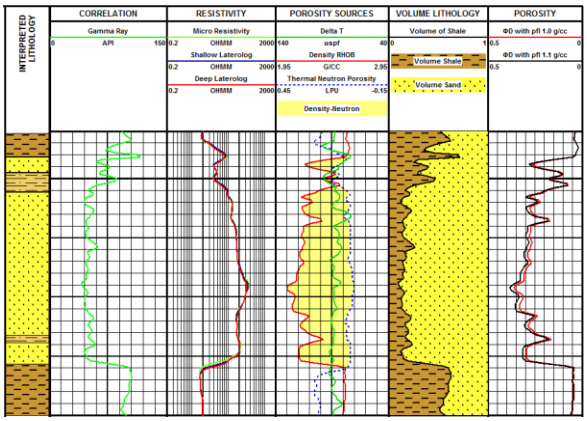

Figure 4. Density porosity calculated from Eq. 4 with different ρfl, Output taken from GEOSUITE software by Geologix

Because of the wider range of matrix density values than fluid density values, errors in estimating the matrix density has a greater effect in calculation of density porosity.

Depth Meters	ΦD with ρfl 1.0 g/cc	ΦD with ρfl 1.1 g/cc	% Difference
1300	0.1768	0.1883	1.15
1320	0.2683	0.2857	1.74
1340	0.3049	0.3247	1.98
1355	0.3293	0.3506	2.13
1380	0.0427	0.0455	0.28

Table 4. Density porosity calculated with different ρfl

In the cases discussed above, the bulk density value derived from the tool is correct, but the calculated density porosity is erroneous because of differences between assumed matrix and/or fluid density values and the actual density values in the formation. Because the wider range of matrix density values than the fluid density values, errors in calculating the matrix density have a larger impact on porosity calculation. Where invasion of a formation is shallow, the low density of the formation's hydrocarbons causes the calculated density porosity to be greater than the actual porosity. Oil does not significantly affect density porosity but gas does (gas effect).

Any time the bulk density of a formation (ρb) is greater than the assumed matrix density (ρma) [e.g., when measurements are made in an anhydrite (ρma = 2.96 gm/cc) but are recorded using a limestone matrix (ρma = 2.71 gm/cc)] the resulting density porosity is negative. In such cases it is important to note that the logging tool is operating correctly but the assumptions made in the conversion between bulk density and density porosity are in correct. In cases like this the porosity is clearly erroneous (as it is negative), the log still yields good information. Negative density porosity is often a good indication of presence of anhydrite or other heavy minerals. Powdered barite is commonly added to mud to increase mud density. When heavy muds are used, high Pe of barite in mud can mask the Pe of the adjacent rock layers. In rough holes, density porosity shows less values than the actual porosity. This is because the sensor pad losing contact to the bore hole wall. There are no environmental correction that can be applied to correct the loss of pad contact.

C. Neutron porosity

Neutron logs are porosity logs that measure the hydrogen concentration in a formation. In clean formation with porosities filled with water or oil, neutron log measures liquid filled porosity (PHIN or NPHI). Neutron log responses may vary depending on –

- Difference in detector types and what they detect (gamma rays and/or) neutrons of different energies
- Spacing between detector and sensor
- Lithology (i.e. sandstone, limestone and dolomite)

The variations due to detector types and tool design are fixed (and are accounted for in data processing). A geologist should remember that the responses of different neutron logs differ from each other unlike other logs and must be interpreted from the specific chart designed for a specific log (i.e., Schlumberger charts for Schlumberger logs,

Halliburton charts for Halliburton logs). The reason behind this is that while other logs are calibrated in basic physical units, neutron logs are not (Dresser Atlas, 1975). If a formation is limestone and the neutron log is recorded in apparent limestone porosity units, apparent porosity is equal to the true porosity. But if the formation is sandstone or dolomite, apparent limestone porosity must be corrected to true porosity by using appropriate charts. Whenever clays are part of formation matrix, the reported neutron porosity is greater than the actual one. This happens because the hydrogen present in clay structure and in the water bound in clay is sensed addition to the hydrogen in pore spaces. Because the processing software of logging tool expects all hydrogens in the formation to reside in the pores, the extra hydrogen is interpreted to be a part of porosity.

D. Neutron - Density Combination: Quick-look lithology and porosity

Although the advent of porosity logs provided substantial improvement in log interpretation, the significant change was the development of interpretive techniques that combines the measurements from different porosity tools. By combining two or three measurements, lithology could be interpreted (rather than having to be known) and a better estimate of porosity produced. The extensive use of neutron-density combination may be due to the fact that they were among the first logging tools that could be physically combined and their data acquired in a single logging run. The response of the combination is such that for reconnaissance evaluation one can forego the crossplot and rely on recognition of the curve patterns (the position of curves with respect to each other) to quickly determine the most likely predominant lithology and formation porosity. The reconnaissance technique works best on the following constraints –

- Both neutron and density curves are in porosity (% or decimal) referenced to limestone units
- Formations are clean, i.e. clay free
- There is no gas in the formation , only water and/or oil

Using only density porosity and neutron porosity, single lithology can be interpreted with little ambiguity. Adding gamma ray may help, as in identifying dolomite from shale. But in mixed lithologies (sandy limestone or sandy dolomite), even the gamma ray does not help much. If the density is of newer litho or spectral type and a photoelectric (Pe) curve is available, the ambiguity can be further lessened, especially in case of mixed lithologies. Pe curve value in mixed lithologies falls between the single lithology values of each member, so some distinction can be made. The effect of clay and gas are greater on neutron measurement than density, with the neutron simultaneously driven lower by gas and higher by clays in a shaly gassy formation resulting uncertainties in interpretation.

E. Neutron -Density Combination: Gas detection

Another technique using neutron and density logs and the identification of curve patterns is that of gas identification. As gas has lower density than oil and water, hence in a gas bearing zone neutron porosity is less than density porosity and the two porosity curves cross each other. The magnitude of the cross over (separation between the two curves) is qualitatively related to the gas saturation. However the cross over is more strongly influenced (again qualitatively) by formation pressure. Low pressure zones, either at shallow depths or depleted from production, tend to show large cross over.

Neutron-density crossover can also be caused by lithological effects, as when the curves are displayed referenced to a lithology that is different from the actual lithology of the formation. It is important to check the header for lithology-reference information as well as knowing the actual lithology of the formation in question before predicting the presence of gas from neutron-density crossover only.

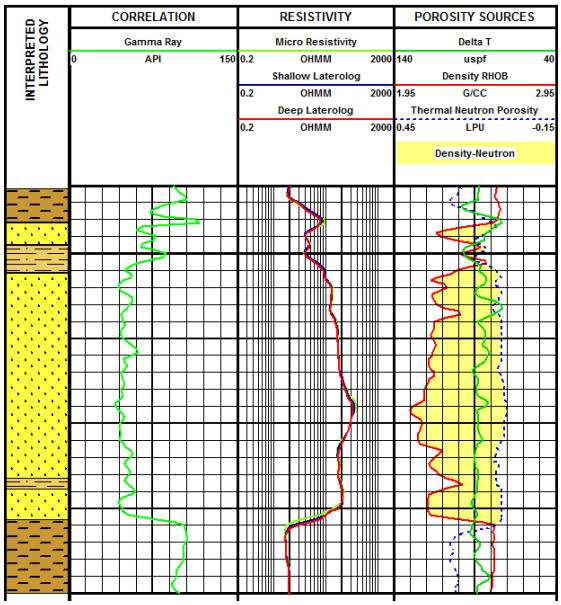

Figure 5. Neutron (NPHI)-Density (RHOB) crossover (yellow shading), Output taken from GEOSUITE software by Geologix

F. Porosity Combinations: Crossplots

Crossplots are graphical way to solve fairly complex relationships using two or three porosity measurements to estimate formation lithology and porosity. All the crossplots have same general format – one measurement is displayed along X axis and another one along Y axis. The measurements are either in porosity units referenced to limestone or, in case of density and sonic logs, they can be in the original measurement units. Superimposed on the plot (as an overlay) are pure lithology lines, usually sandstone, limestone and dolomite. Porosity is indicated along each of these lines. In interpretation the values of the two measurements are plotted and the intersection of those values in crossplot determines both the porosity and lithology of that point. A point is interpreted to be the mixture of two lithologies if it lies between two lithology lines and porosity is estimated by joining points of equal porosity on the two lithology lines and extrapolating

between the lines of equal porosity. It should be noted that all the interpretations are unique. In fact, the data often plot in such a way that there are two possible lithology pairs, and the decision of which to choose lies with the interpreter's knowledge of the area (or the application of other dataset). The conventional method to correct gas affected crossplot data is to adjust the crossplotted point by moving a certain angle downward towards the right (Figure 6); wherever the point touches on the clean matrix line, it should directly show the porosity at that point. However correcting a data point to a clean matrix line also requires another source of lithology reference, so that one is sure as to which matrix line they do intersect while shifting the gas affected point by a particular angle towards down right. It is subjective as to which lithology line it is to be stretched to.

Other few minerals can also be plotted on the crossplot as distinct points (rather than lines indicating varying porosity), like anhydrite etc. as neutron-density crossplot in Figure 6. Log values for the other pure minerals are available in the log interpretation chart books provided by most well log acquisition companies. Although the existence of pure and thick beds of some minerals is very rare, the location of the mineral point in crossplot (and the shift of data towards the point) may give some indication that the mineral is present in the formation of interest.

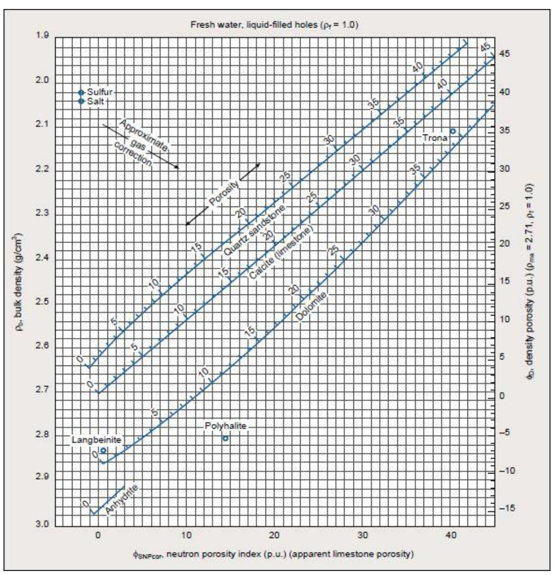

Figure 6. Neutron (NPHI) - Density (RHOB) crossplot, Courtesy: Schlumberger Chart book, 2000

In some plots choice of the lithology pair significantly affects the predicted porosity value. Advanced crossplots takes into account three mineral compositions, which is calculated via ternary plots. Lithology triangles are defined to determine these compositions. For this, the geologist has to have a very good idea about the possible lithologies in the area. It is only then that he will be able to draw lithology triangles. It therefore becomes highly subjective while determining complex lithologies by advanced crossplots. Say in a Lithology Identification Plot, a point falling close to anhydrite could have been a ternary mixture of Quartz-Dolomite-Anhydrite or Calcite-Dolomite-Anhydrite. Depending upon the geologists' knowledge he is free to draw triangles he thinks is most suitable.

Limitations and uncertainties with porosity crossplots –

- In rough holes or in heavy drilling muds, density data might be invalid, thus creating problems in using neutron-density and density-Pe crossplots.
- In density-sonic crossplot lithology lines are closely spaced, so any uncertainty in the measurements produces large changes in the lithology and porosity estimates.
- As Pe measurement will not be present in wells logged before about 1974, density-Pe crossplot cannot be applied for those wells.
- Sonic-neutron crossplot is not that popular as the combination of sonic and neutron data (without density) is not common.
- Choice of lithology pair has a significant effect in porosity estimation while dealing with density-sonic crossplot.

G. Fluid saturation – Archie's equation

Archie's equation says-

$$Sw = [(a*Rw)/(Rt*\Phi^m)]^{1/n} \quad \ldots\ldots (5)$$

Where Sw = formation water saturation, Rw = formation water resistivity, Rt = true formation resistivity, Φ = porosity, m = cementation exponent, n = saturation exponent

Once the resistivity and porosity are calibrated or calculated from other logs, estimates of water saturations can be generated. The Archie equation is the standard for calculating water saturation in clean, porous rocks. There are several variations to the basic Archie water saturation equation, including the Indonesian, Simandoux, Waxman-Smits, and Dual Water formulas. All of these models were developed to fit a specific dataset and have limitations (Fertl and Hammac, 1971). The analyst needs to determine which of these models best fits the available data and input logs based on the reservoir characteristics. Additionally, uncertainties exist in choosing the model parameters, including cementation exponent, '*m*', saturation exponent, '*n*' and Archie constant, '*a*'.

First, Archie's equation assumes all porosity is interconnected and that there is a uniform grain packing. Very few rocks in the real world meet these conditions. All shaly sand equations (e.g., Waxman-Smits, Dual Water, Simandoux, Indonesian etc.) try to account for the discrepancies between the calculated results and the empirical correlations in Archie's equation, but they cannot be perfectly accurate. Second, laboratory work, although it can guide the analyst in determining the parameters, has its own range of uncertainty. For example, fractures, vugs, uncommon minerals or rocks, and other reservoir characteristics can all affect the data analysis. Moreover, these parameters may vary widely over the extent of the reservoir. Core analysis, Pickett and Magnolia plots are

commonly used to derive the average values. Variables '*m*' and '*n*' derived from the log data can sometimes be used.

Discussion

- Data from well-log and petrophysical analyses are usually the main input for reservoir modeling. Typically the data is given to the reservoir modeler without communicating the uncertainty in acquisition, processing, and interpretation. Reservoir modelers often assume the well-log data as hard data without uncertainty. To account for the uncertainty, both petrophysicists and modelers need to question the data and communicate the uncertainty from the various processes. Some simple questions can greatly help to understand the uncertainty in the well-log data, including –

- Are the data simply raw data dumped into a quick model or have they undergone a set of rigorous checks and environmental corrections? Time spent on checking and correcting the input data should increase the level of confidence in the results.
- Have the data been normalized and if so, to what standard? Normalization should remove systematic errors and noises from the data. However, it is very dependent on the standard chosen to normalize to. If a certain facies is chosen, for example, a thick marine shale or a low porosity zone, all the wells need to have that interval for the normalization to be representative. Otherwise, true variability of the rock in the wells will be masked or eliminated.
- Is there a description of the correction and analysis process and a justification for the analyst's parameter selection and methodology?
- Was all the available data used and incorporated in the analysis? Everything being equal, the more data is available and appropriately used in the processing methodology, the less uncertainty is in the final petrophysical results and reservoir model.
- Did the log analyst perform sensitivity studies of porosity and saturation parameters? Sensitivity analysis can help understand and identify the ranges of these properties, and therefore help quantify the uncertainty in the data.

Conclusion

Raw log data or un-rigorously processed log data can cause either over- or under-estimation of subsurface resources in the reservoir model as a result of data error. Propagation of the uncertainty from well-log and petrophysical analysis into reservoir model can be quite complex, especially for local uncertainties in the distribution of the reservoir properties within the reservoir. Geological and petrophysical interpretations are non-unique-solution problems, and there is no absolutely correct recipe to follow.

The key objectives for petrophysical analysis in a reservoir study is to reduce the systematic errors caused by borehole effects, tool and vendor types, resolution differences, depth shifts and other acquisition factors, and to perform a consistent analysis between wells. While there may still be uncertainty in the results caused by random error, these should be minimized for the ongoing interpretation. The output can then be used more confidently in the reservoir modeling. Integration is the key to any reservoir study that can validate petrophysical analysis. Too often, each discipline - petrophysics, geology, geophysics, or reservoir engineering, focuses on its own interpretation and analysis with little input from the others. Uncertainties inherent in the individual disciplines are often not communicated to the reservoir modeler, who uses the data as the accurate hard data, rather than as the result of a number of choices and assumptions in the interpretations. Integration enables team members to be involved in defining the uncertainty in the data and an acceptable uncertainty range for the project. Only when the uncertainty range of the data from the well log and petrophysical analysis is communicated to the other team members and management, can the uncertainty be accounted for in reservoir characterization and modeling.

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