

Digital Log Data to Mechanical Rock Properties for Stimulation Design

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INTRODUCTION

A successful completion program depends upon accurate reservoir parameters determined from petrophysical analysis. The workflow to achieve this is well known to expert petrophysicists but geologists, engineers, and managers may not be aware of the detailed steps that lead to an accurate petrophysical model. What may be even less appreciated is the fact that many stimulation designs are faulty because of poor quality sonic and density data, or because the petrophysical analysis model is oversimplified or poorly executed due to lack of experience on the part of the analyst.

For determining elastic properties of rocks for stimulation design, the raw log data is often inadequate due to rough borehole conditions and light hydrocarbon effects. Since stimulation design software expects data for the water filled case, the light hydrocarbon effect alone would lead to erroneous elastic properties, and thus in closure stress predictions. Add in some rough borehole effects, and you have a meaningless set of elastic properties for stimulation modeling.

This paper presents a practical, repeatable solution using digital open hole log data to perform routine and advanced formation analysis, and how these results in conjunction with log reconstruction lead to more accurate stimulation design.

WORKFLOW

Step 1: Curve Inventory

The LAS (Log ASCII Standard) files must first be reviewed to determine which curves are available for calculations. It is often useful to open the LAS files with a text editor, before they are loaded into the petrophysical software package, to review curve data and parameters.

Step 2: Quality Checks

The logs must be checked to make sure that all curves are on depth with regard to each other. This is not as much of an issue with modern data, but older data sets usually need adjustment.

- An expanded depth plot is useful for this – typically gamma ray is taken as being on depth and the other curves are shifted to match.

The other important thing to check is that neutron and density porosities are calculated using the same matrix scale (quartz, calcite or dolomite).

Step 3: Identify Intervals with Questionable Data

Caliper and density correction logs are used to identify borehole intervals which are washed out (larger diameter than the drill bit).

- Often the standard calculation sequence must be modified to deal with erroneous data over out-of-gauge hole intervals.

Step 4: Calculate Volume Shale

Petrophysicists define volume shale as the bulk volume of the rock composed of clay minerals and clay bound water.

The gamma ray (GR) log is typically used to calculate shale volume. If the rock is radioactive, a non-linear relationship must be used between clean and shale lines. A spectral gamma ray log breaks out thorium, potassium and uranium, and is very useful in radioactive sands.

Shale volume can also be calculated from the spontaneous potential (SP) log, resistivity log and neutron density separation.

When x-ray diffraction (XRD) data are available, the calculated shale volume should be calibrated against XRD data. Calibration is very important when evaluating radioactive reservoirs.

Step 5: Calculate Kerogen Weight Fraction and Convert to Volume Fraction

This step is required for kerogen-rich reservoirs only.

Kerogen weight fraction can be calculated from the resistivity log and a porosity log, using Passey or Issler methods. The Passey model is often called the “DlogR” method, with the “D” standing for “Delta-T” or sonic travel time. He also published density and neutron log versions of the equations. Issler’s method, which is based on WCSB Cretaceous data is preferred as no baselines are needed. It still needs a scale factor for deeper rocks.

Mass fraction organic carbon results from log analysis MUST be calibrated to geochemical lab data using the scale factor and scale offset. These scale factors will vary from place to place even within the same geological horizon. Using the Passey or Issler models without local calibration is strongly discouraged – results are often 2 to 3 times too high.

Kerogen volume fraction is calculated by converting the TOC weight fraction. The lab TOC value is a measure of only the carbon content in the kerogen, and kerogen also contains oxygen, nitrogen, sulphur, etc., so the conversion of TOC into kerogen has to take this into account. The kerogen conversion factor is the ratio of carbon weight to the total kerogen weight. The factor can range from 0.68 to 0.95, with the most common value near 0.80.

Kerogen mass fraction is then converted to volume fraction using a density in the range of 1200 to 1400 kg/m³.

Step 6: Identify Gas Intervals

Gas intervals are typically identified by neutron-density cross over. Sometimes crossover may be masked by the presence of shale. To this end, the shale corrected neutron and density logs must also be checked for crossover. Also keep in mind that the matrix value used to calculate neutron and density porosity must be appropriate for the interval being evaluated (Running limestone matrix values in a sandstone interval can result in cross-over, not caused by the presence of gas).

Step 7: Identify Coal, Salt and Anhydrite Intervals

Coal intervals are identified by high neutron porosity and high density porosity log readings. Coals usually have fairly low gamma ray log readings, but this is not always the case. Coal intervals are often washed out.

Salt intervals are identified by low gamma ray log readings, along with the bulk density log reading close to 2000 kg/m³, and a neutron porosity value close to zero. The sonic log will read close to 220 us/m over salt intervals.

Anhydrite is identified by low gamma ray log readings, along with the bulk density log reading close to 2980 kg/m³, and a neutron porosity value close to zero.

Step 8: Calculate Total Porosity

There are numerous methods which can be used to calculate porosity. In general, porosity from the neutron density cross plot is the preferred approach.

- neutron–density cross plot
- density only
- sonic only
- neutron only
- neutron-sonic cross plot

Step 9: Calculate Effective (shale-corrected) Porosity

The total porosity must be shale-corrected. The shale corrected porosity is called effective porosity. If the reservoir is kerogen-rich, a kerogen correction will also need to be applied to the porosity model. When available, core data should be used to calibrate the porosity model.

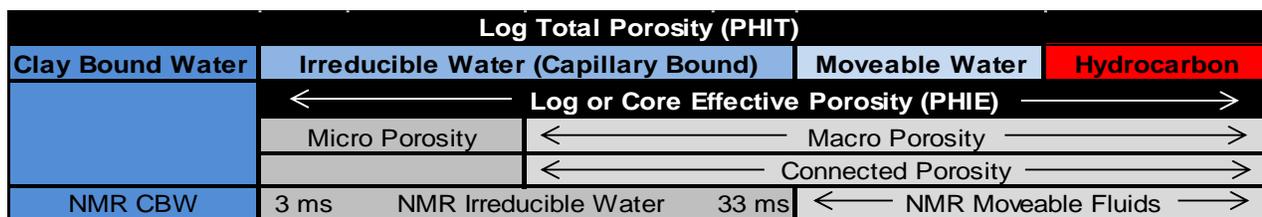


Figure 1: Pore Space Schematic

Step 10: Calculate Lithology

The lithology model must match the interval being evaluated and is dependent on the available data. The number of minerals which can be solved for is equal to the number of curves used as input. A discriminator can be used to identify anhydrite, salt and coal intervals.

- three mineral model from PE, Neutron and density
- three mineral model from sonic, density and PE
- two mineral model from sonic
- two mineral model from density
- shale sand model from gamma ray

When x-ray diffraction (XRD) data are available, the calculated mineral volumes should be calibrated with the XRD data.

Step 11: Calculate Water Saturation (SW)

The modified Simandoux equation works well for most situations. The modified Simandoux equation reduces to the Archie equation when volume shale equals zero. When low resistivity shale is present, the modified Simandoux equation accounts for the resistivity of the shale and generates a more accurate water saturation.

- tortuosity, cementation and saturation exponents (a, m and n) are required
- R_w at reference temperature is required and must be corrected to formation temperature
- shale resistivity
- a deep resistivity log reading and accurate porosity are required

When available, core data should be used to calibrate the saturation model.

Step 12: Calculate Permeability Index

Permeability from logs should be considered an index only and must be calibrated. When core data are available, the permeability-porosity (K-PHI) cross plot, can be used to describe permeability as a function of porosity.

- Wylie-Rose
- Coates-Denoo
- Exponential model
- Power Law model
- Lucia Rock Fabric model

The calculated permeability index must be corrected to in-situ conditions. The best way to do this is to use dynamic well test data to quantify flow capacity. The flow capacity from the well test is then used to determine a calibration factor which is applied to the permeability index.

Step 13: Reconstruct Sonic and Density Log Curves

Reconstructed or synthetic logs have become an important part of a competent petrophysical workflow. Sonic data are affected by one or several of the following: fractures, laminations, TOC, gas content, external stress, temperature, borehole conditions, pore pressure and pore fluid saturation. Using bad (or slightly affected) sonic data results in erroneous elastic properties (Poisson's ratio and Young's modulus).

The goal is to use only valid data in the petrophysical analysis, omitting bad data from the model. Reconstructed logs are generated from results using the Log Response Equation.

There are two reasons for reconstructing the well logs: The first is to verify that the parameters used in all steps are reasonable. In good borehole conditions, the reconstructed logs should be close overlays of the original logs. If they are not, possibly some bad data snuck in, or some parameters in the overall model are wrong. Often some investigation is required to chase down the guilty party and rectify the problem. A good match between reconstructed and original logs, over good bore hole intervals, is not a guarantee of success, but it is one more piece of evidence pointing in that direction. The second reason for reconstruction is to prepare a strong foundation for calculating rock mechanical properties. Mechanical properties developed from raw logs often contain spikes and noise, or worse, that destroys the stimulation design results. It is strongly recommended that stimulation design should ALWAYS use edited or reconstructed logs, which presupposes that sufficient time and talent be allowed by management for this step to take place.

During reconstruction, missing logs can also be created, such as the shear sonic curve, for use in the mechanical properties calculation or for comparison to other wells in the project.

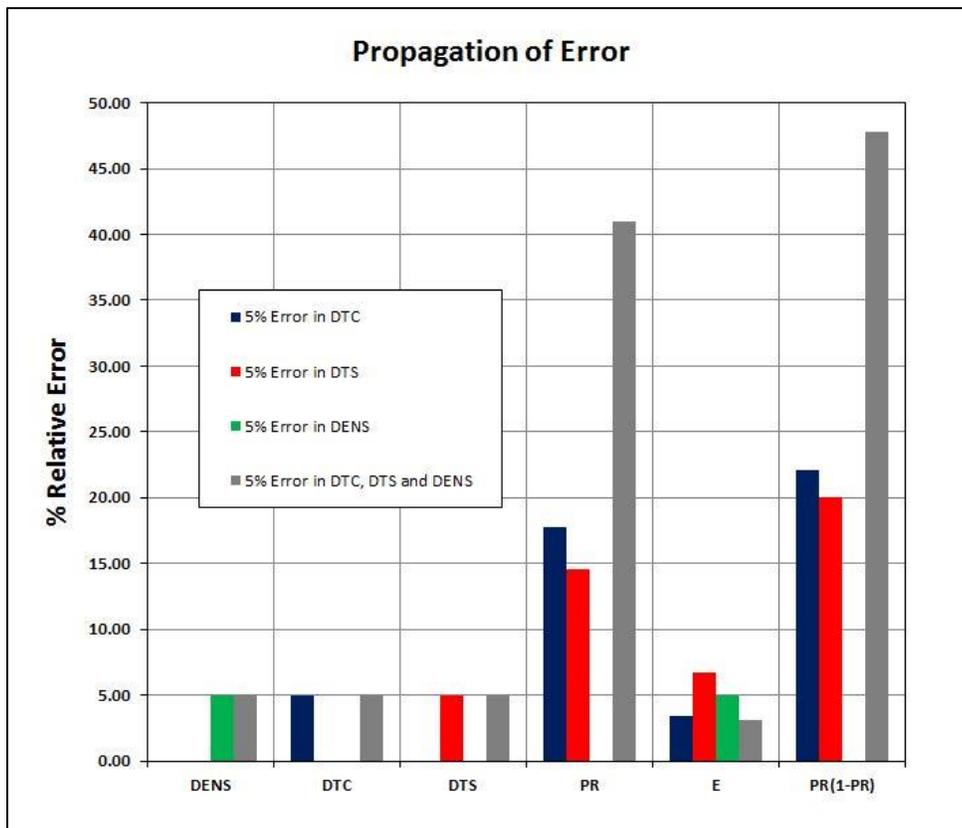


Figure 2: Effect of error propagation of a +/-5% error in DTC, DTS, DENS, and all three combined on calculated rock properties.

Step 14: Calculate Dynamic Mechanical Rock Properties

Hydraulic fracture design depends on an accurate evaluation of rock mechanical properties based, in turn, on an advanced petrophysical analysis. Most frac design programs have only a rudimentary capacity to perform petrophysical analysis. Worse still, frac design software uses the raw, unedited log data with all its problems. Nothing good can come from this. So it is better to do the work outside the frac software and import the mechanical property curves.

The first step to accurate mechanical properties is a reconstruction of the sonic shear and compressional and density data to remove the effects of bad hole and light hydrocarbons. The frac design programs need the water filled case so the reconstruction is always needed in gas zones. More information on how to do this can be found at www.spec2000.net/10-mechsxn.htm.

The usual outputs from this step are shear modulus, velocity ratio, Poisson's ratio, bulk modulus, Young's modulus, Lamé's constant, and a brittleness coefficient. The original and reconstructed log curves, and the lithology track, are displayed with the mechanical properties results.

Dynamic lab measurements (acoustic) can be used to help calibrate the mechanical properties calculated from the petrophysical model. In the absence of lab data, most of these results must fit within known ranges, depending on lithology. If values are out of range, the input data should be considered suspect, and the log reconstruction procedure must be checked. This in turn depends on the current state of the petrophysical results, requiring a double check of all parameters and calibration steps. This kind of manual iteration is a normal part of a petrophysicist's daily grind.

Another approach can be used when shear sonic data are absent, but compressional sonic data are available: Barree's cross plots can be employed to calculate Poisson's ratio and Young's modulus. This approach also requires that bulk volumes of quartz, limestone, dolomite, shale and coal be known from the lithology model.

Step 15: Estimate Static Mechanical Properties

Estimated static mechanical rock properties are needed as input for hydraulic fracture simulation work. Static values differ from dynamic values because wave propagation is a phenomenon of small strain with a large strain rate: rocks appear stiffer in response to an elastic wave, compared to a rock mechanics laboratory (triaxial) test, where larger strains are applied at lower strain rate. The weaker the rock, the larger the difference between elastic properties derived from acoustic measurements (dynamic) and those derived from triaxial measurements (static). This accounts for the marked difference between dynamic and static Young's moduli. However, the difference between dynamic and static Poisson's ratio is very small, and is generally not considered.

Triaxial (static) lab measurements can be used to help estimate the difference between dynamic and static moduli values. In the absence of lab data, most of these differences should fall within known ranges, depending on lithology,

Many transforms have been published which can be used to convert dynamic modulus to static modulus.

Step 16: Calculate and Calibrate Closure Stress

Closure stress is calculated using Barree's Total Stress equation and must be calibrated to the area. The best way to calibrate closure stress is to review fracturing work, or perform a minifrac. In tectonically active areas, the closure stress calculated from logs will be too low and will need to be increased. To increase closure stress, two different approaches can be used: The first uses a stress offset which is added to the original calculated stress, with the end result being a shifted closure stress by a constant amount. The second uses a strain offset multiplied by the Young's Modulus of the rock, resulting in intervals with high Young's Modulus having a greater closure stress shift than intervals with low Young's Modulus (the stress offset is related to the stiffness of the rock). Generally, the strain offset approach is favoured.

- true vertical depth (TVD) is required for deviated wellbores
- overburden gradient
- pore pressure gradient
- Poisson's ratio
- Young's static modulus
- horizontal Biot's poroelastic constant
 - set to unity (1)
- vertical Biot's poroelastic constant
 - often calculated using effective porosity

CONCLUSIONS

This recommended workflow for calculating mechanical rock properties from digital log data has proven successful in many challenging reservoir environments, worldwide. The steps take some time to complete and sufficient time and talent should be allowed by management for the process.

The reconstruction step is particularly important for sonic and density logs. Small input errors amplify to become surprisingly large due to the inherent nature of the equations that are used to obtain rock mechanical properties. To reduce error propagation issues, reconstructed or synthetic logs are an essential input to stimulation design software packages. Creating such logs requires a significant effort to first produce a competent petrophysical analysis. However, that analysis has other uses, such as determining completion intervals and the best location for horizontal wells, not to mention the more usual applications such as reserves and productivity estimates. So the effort is not wasted.

In the end, the cost of the full analysis and reconstruction is trivial compared to the cost of completion, or worse, an unsuccessful completion design.

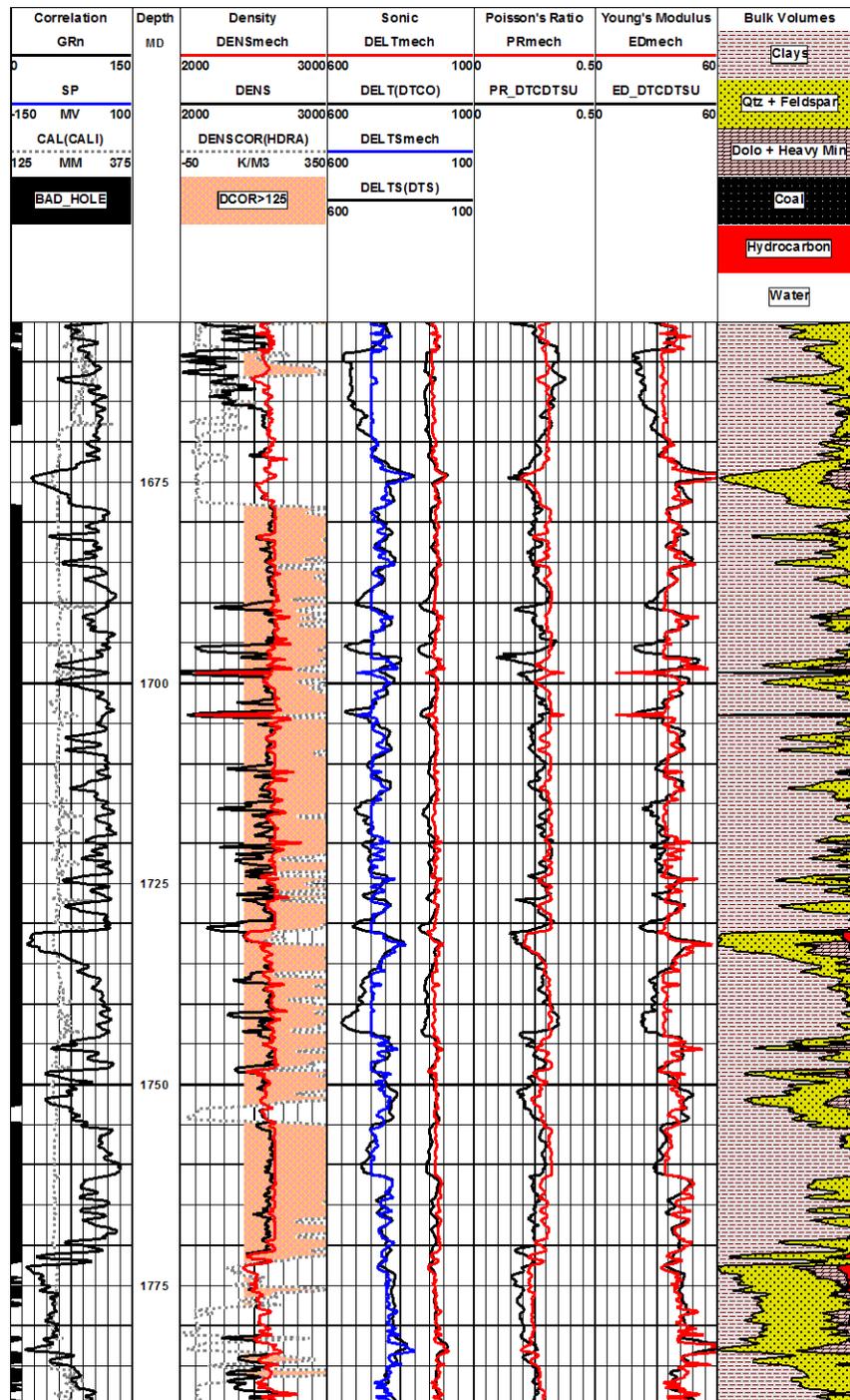


Figure 3: Example of log reconstruction in a shaly sand sequence (Dunvegan). The 3 tracks on the left show the measured gamma ray, caliper, density, and shear and compressional sonic. Original density and sonic are shown in black, modeled logs are in colour. Computed elastic properties are shown in the right hand tracks. Results from the original unedited curves are shown in black, those after reconstruction are in colour. Note that the small differences in the modeled logs compared to the original curves propagate into larger differences in the results, especially Poisson's ratio and Young's modulus. To calculate an accurate total closure stress, the reconstructed logs must be used as input.

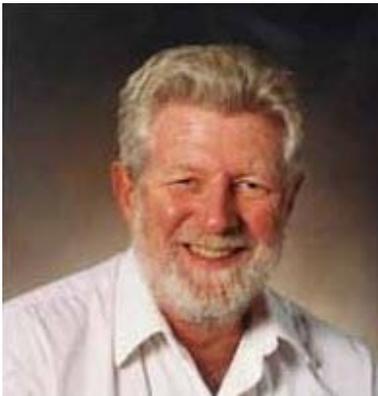
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