A Sample to Core-Scale Deep-Dive Through Two Vuggy Pre-Cambrian Carbonate Reservoirs, Oman

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Abstract

The assessment of reservoir potential in carbonates associated with complex diagenetic histories is notoriously challenging because pore systems are often multi-modal; pores, vugs and fractures span the microscale (μm) to macroscale (cm) domains. Thus, reservoir-scale estimates of effective porosity and permeability in carbonates depend on our ability to integrate a range of observations across scales.

We aim to constrain the stratigraphic distribution and geological controls on fundamental rock properties in two Precambrian vuggy carbonate reservoir units through integration at the sample to core scale. We focus on two cored wells (Well 1, Well 2) from the Nafun Group, onshore Oman, sampling the Buah Formation and the Khufai Formation, respectively. Our dataset includes traditional petrographic, image analysis, mini-perm (probe) and conventional core analysis (CCA) data, coupled with core-scale sedimentological and whole-core computed tomography (CT) data. The two reservoir units comprise calcareous to dolomitic stromatolitic, grainstone and mudstone lithofacies, interpreted as deposited in middle to inner ramp settings. The complexity of both formations lies in the diagenesis of the vuggy and fractured pore systems.

A semi-automated segmentation workflow was used to quantize the CT volumes into seven phases including vugs. A watershed of touching vugs was applied to the CT vug volumes, followed by extraction of a range of shape descriptors on a vug-by-vug basis, including volume and shape factor. The CT analysis shows the pore system in Well 2 is more strongly coupled to lithology, including intergranular secondary porosity within grainstones and vuggy stromatolite beds.

Next, we applied a rolling mean to the CT vug segmentation data and joined to the discrete CCA data (taking the nearest CT slice). We applied multiple linear regression modelling of the CT data for the prediction of bulk CCA porosity and permeability on a whole-core, continuous, well-by-well basis. The goodness-of-fit of the four models is variable but generally favorable. r2 values are 0.47 and 0.55 (Well 1) and 0.82 and 0.65 (Well 2), for each porosity and permeability model, respectively. Thus, at least in Well 2, core-scale features proxy for bulk rock properties, confirming that it is possible to model bulk porosities and permeabilities from whole-core CT data. The modelled permeabilities only weakly correlate with the mini-perm analyses, likely because the latter is prone to analytical error. Overall, good agreement between the modelled and 'ground-truth' CCA data shows core-scale modelling is more reliable compared to mini-perm measurements.

Integration with petrographic thin section analysis helps to contextualize the CT model results. The ability to accurately model bulk rock properties using core-scale features is best viewed in terms of the mechanism(s) for pore development in the two wells. Coupling of macroscale

and bulk rock properties in Well 2 suggests closed system migration of dissolved carbonate from donor microenvironments (e.g., vugs) into receiver matrix domains was quantitatively more important than in Well 1.

The sample-to-core approach presented offers a means to derive continuous, high-resolution estimates for porosity and permeability at reservoir scale, independent of established approaches. Comparison with conventional well and image logs and application of the workflow to other reservoir sections are identified as areas for future work.