Factsheet
Permeability and facies

Formation permeability

Permeability and hydraulic conductivity describe the capacity of a rock layer to transmit water or other fluids. Whilst permeability is a rock property related to the porosity (in solid rocks: fraction of voids in the rock matrix), hydraulic conductivity also includes the secondary porosity of the rock layer such as faults, fractures and karst conduits, which by far outreaches the effect of the primary porosity (matrix permeability). Specifically in carbonate rock reservoirs the groundwater yield is controlled by the secondary porosity (cf. Factsheet Faults).

In contrast to the permeability of rock which is measured on samples in the laboratory (e.g. Bohnsack et al. 2020), the hydraulic conductivity has to be determined in the natural rock formation, requiring hydraulic borehole tests such as pumping or drill-stem tests to ensure a reliable evaluation (Birner et al. 2012). Through these tests, the hydraulic conductivity of subsurface rock formations can be derived from the production or injection rate of the well and the observed gradients (rise or drawdown of water table, pressure build-up or reduction). However, this does not give a direct reading of the reservoir rock permeability or hydraulic conductivity, but primarily an integral value over the test horizon (aquifer thickness H [m]), the transmissivity T [m^2/s]. The hydraulic conductivity can be directly derived from the transmissivity in homogenous and isotropic aquifers only. For solid rocks with divisional surfaces controlling the permeability, thus intrinsically anisotropic with respect to groundwater distribution, the term formation permeability is used (i.e. the quotient of transmissivity T [m^2/s] and the tapped thickness H [m] of the reservoir) to describe the average hydraulic conductivity [m/s] of the rock layer per meter thickness expressed as the permeability coefficient k_f.

Regionalization of K resp. k_f coefficients and their representation as trustworthy contour maps or interval polygons is feasible only if a reasonable number of non-clustered hydraulic borehole tests of the reservoir are available. This is rarely the case for reservoirs at an early stage of assessment. In HotLime, consequently, a spatial representation of the formation permeability could be prepared only for Case Study 1, the Jurassic reservoir of the Molasse Basin (Figure 1 and map 2 of Case Study 1 map set), where more than 50 geothermal installations are in operation and hydraulic tests on further deep drillings are on hand. However, for such reservoirs featuring a large number of hydraulic borehole tests, spatial representation of the formation permeability have to be considered more a hindcast or back-testing, rather than a robust tool for predictions in areas away from the hard data clusters. Areas with scarce and scattered base data feature a large uncertainty, inappropriate for any reliable prediction of the formation permeability (dashed lines in Figure 1 and map 2 of Case Study 1 map set).

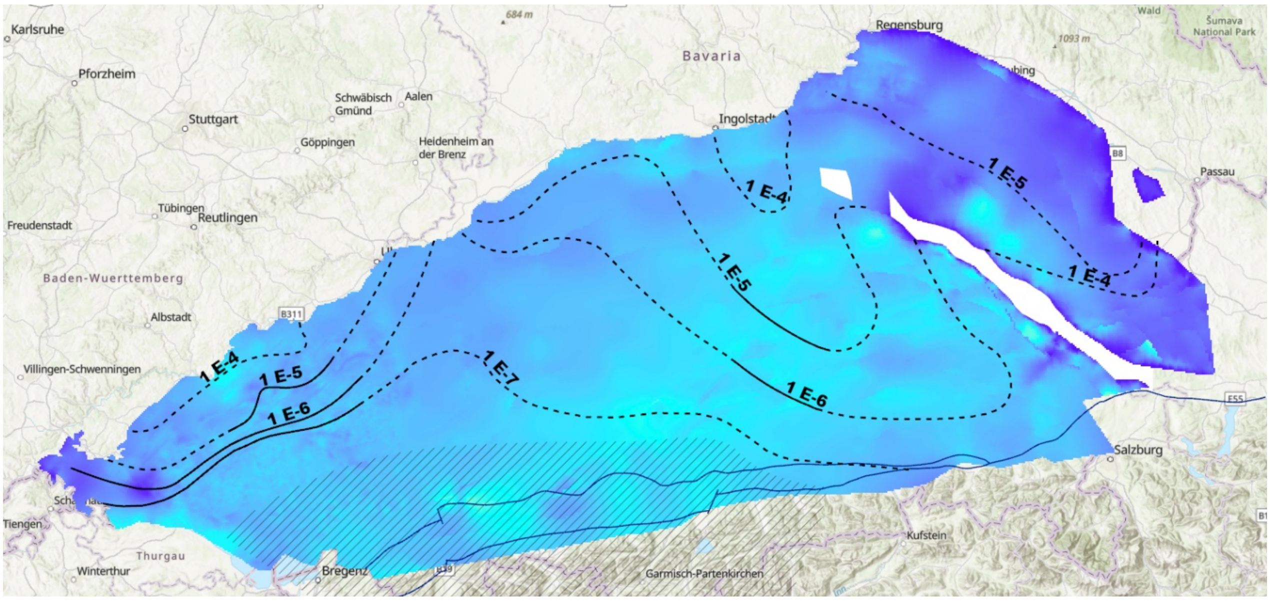

Figure 1: Formation permeability distribution pattern of the Upper Jurassic carbonates underneath the Central Molasse Basin, as investigated in HotLime's Case Study 1 (modified after Birner et al. 2012, amended using the modelling results from GBA & Erdwerk 2019).
Solid lines: formation permeability distribution proven by a dense cluster of hydraulic borehole tests, dashed lines: inferred from scattered data, hachured: transition zone to low permeability facies (k_f << 1 E-7) of the Helvetic Basin underneath Subalpine Molasse and Alpine nappes, plotted on the "gross thickness of reservoir" distribution (cf. map 2 of Case Study 1 map set).

Facies distribution

Facies distribution gives a primary qualitative characterization of a carbonate reservoir. In regions characterized by very poor direct petrophysical measurements, facies distribution, combined with data from the literature, provides an approximate input to characterize the geothermal reservoir.

Regional facies distribution maps can point out the most interesting prospecting areas in a geothermal region, firstly by separating shallow water from basinal units. In addition, where it is possible to distinguish in more detail the different sedimentary environments (e.g. evaporation platform, restricted platform, lagoon, high-energy shoal, and low-energy shoal in open platform) they allow prediction of primary porosity and possibly the relation with the permeability of the reservoir (Ling et al. 2014; Thomas et al. 2020). In fact, facies are characterized by rock fabrics that include diagenetic overprints as well as depositional textures and diagenesis plays an important role in forming most carbonate pore space (Lucia 2007).

The flow characteristics of carbonate reservoirs are controlled by the combination of depositional and diagenetic processes. Depositional processes shape the initial pore size distribution and the geometric relation between different depositional facies. On the other hand, the diagenetic overprint can modify the pore size distribution and controls the productivity of different depositional facies.

In karstified reservoirs, the quality of the reservoir itself and the flow characteristics are controlled by diagenesis. For this reason, understanding the relation between carbonate facies, faults, fractures and karst conduits in carbonate units allows better characterization of the reservoir and improvement of the geothermal yield.

The map 2 of Case Study 5 map set shows the areal distribution of the prevalent facies according to the analysis of well stratigraphies; considering, for each well, the ratio between thickness of the facies (e.g.: shallow water, basin) and that of the whole carbonate reservoir.

References

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