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Modeling Stimulation Enhancement of Naturally Fractured Reservoirs

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SUMMARY

Conductivity enhancement of natural fracture networks by stimulation using low-viscosity fluids results in the development of a Connected Stimulated Network or CSN. Within the geothermal community this is considered to be the only effective means of creating an Enhanced (Engineered) Geothermal System in an otherwise tight rock. Production of gas or oil from mud rock (so-called “shale gas” or “shale oil”) is also believed to require stimulation of pre-existing natural fractures.

Modeling stimulation enhancement of naturally fractured reservoirs

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Modeling the creation and modification through shear and other deformations of these CSN's has generally been expensive due to the belief that a Discrete Fracture Network (DFN) is required, and that each fracture must be modeled as a unique entity. Subsequent reservoir models are generally created by converting the DFN into one component of an equivalent dual porosity dual permeability system. The computational costs associated with this approach are significant, and furthermore we have a limited ability to determine the actual distributions of pre-existing fractures and flaws. Thus we either run the simulation on a sufficient number of realizations of the DFN that the statistical variations can be established, or we rely on seismic, microseismic or other a priori data to condition the DFN.

An alternative approach is to assume that there exists a representative volume which can be described in terms of the likelihood of a fracture existing within that volume determined using the same information as is required to prepare a DFN. In general, this requires that we detect and orient fractures in wellbores or that we use reservoir analogs or physical models. The behavior of the representative volume can then be quantified in terms of the influence of the stress field and of stimulation or depletion on each of the fractures, weighted by their likelihood of existence. This paper illustrates the approach using data from two field studies – one of these is a data set collected in the Huron formation in the northeastern United States; the second is from an EGS project in Nevada. In both cases reasonable consistency between the model result and actual measurements was obtained. While this suggests that the approach is reasonable, it does not obviate the need for better explicit models or for better methods of detecting fractures in the far field.

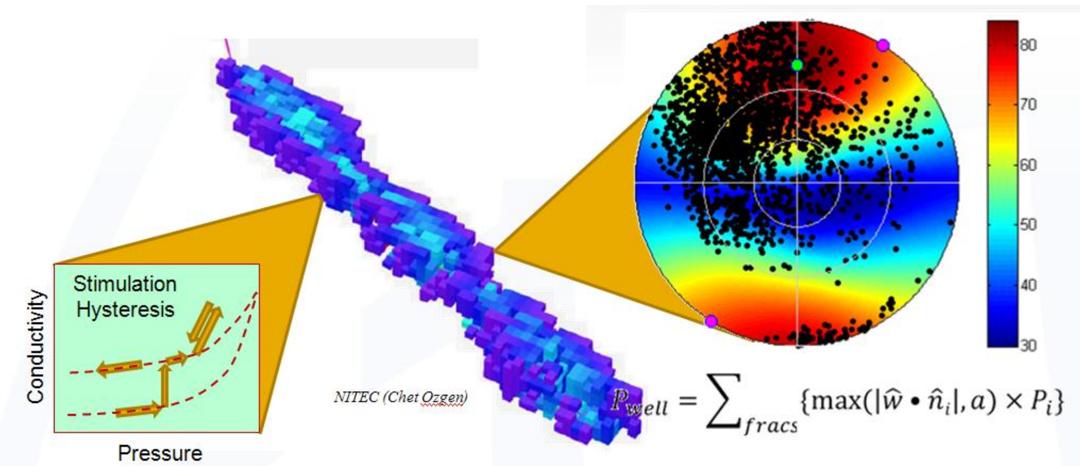

Figure 1. Illustration of the modeling approach (central image courtesy of NITEC, Chet Ozgen), in which the fracture contributions to flow are computed using a weighted sum (right), the reservoir properties can vary in time and space, and the flow and storage properties of each cell are determined for purposes of flow computation from an equivalent model which honors the expected behavior of the fractures (e.g., left).