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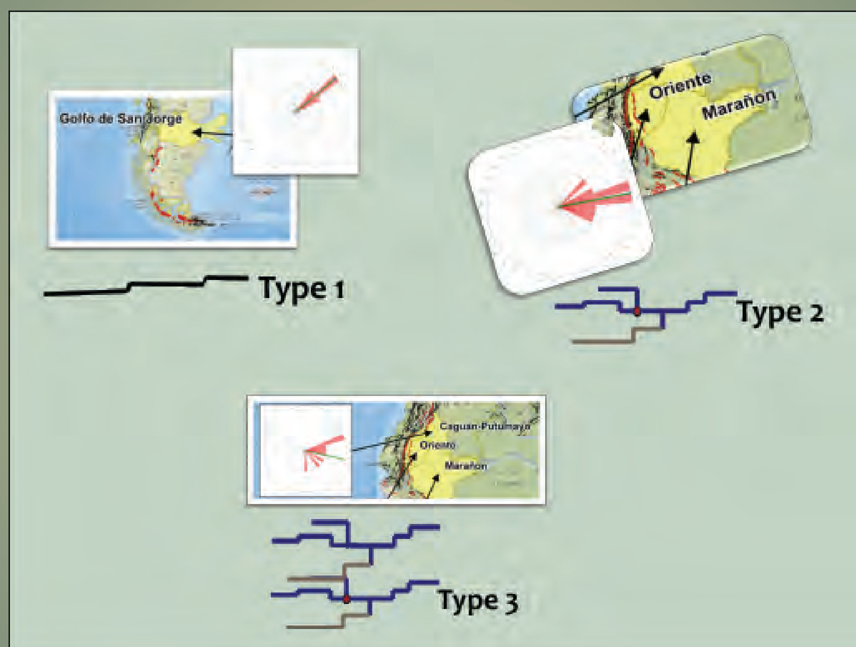
Large-scale Geologic Controls on Hydraulic Stimulation



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Background

When simulating hydraulic fracturing, the analyst has historically prescribed a single planar fracture. Originally (in the 1950s through the 1970s) this was necessitated by computational restrictions. In the latter part of the twentieth century, hydraulic fracture simulation evolved to incorporate vertical propagation controlled by Young's modulus, fluid loss, and the minimum principal stress. With improvements in software, computational capacity and recognition that in-situ discontinuities are relevant, fully three-dimensional hydraulic simulation is now becoming possible.

Advances in simulation capabilities enable coupling structural geologic data (three-dimensional representation of stresses, natural fractures, and stratigraphy) with decision making processes for stimulation – volumes, rates, fluid types, completion zones. With this interaction between simulation capabilities and geological information, low permeability formation exploitation can be extended to regions outside the currently dominant basins.

Motivation

Currently, the ability to estimate OGIP or OOIP often exceeds the ability to stimulate and economically extract this resource. This inadequacy applies to many tight as well as ultra-low permeability formations – sands or shales. Improved simulation of hydraulic stimulation, amalgamating geologic information (particularly stresses and discontinuities) with controllable engineering parameters – could be of value. Recognizing this, the goals of this work program have been to:

- More fully enfranchise geologic regimes in the stimulation design process. A workflow has been developed (Chapter 3).
- Move the stimulation methodology planning farther upstream. A tool for inferring stresses and discontinuity characteristics during drilling is presented in Chapter 2.
- Develop diagnostic methods that realistically reflect the geologic environments of concern. These would be methods that could be used before, during, and after hydraulic stimulation. Dual porosity methods have been explored for quantifying natural fracture properties - spacing and aperture (Chapter 4).
- Assess geologic signatures that will allow more rock be exposed to recoverable stimulation fluids, to enable fracture aperture to be maintained and to do this with minimized or optimized volumes of treating fluids. This has been done by focusing on post-shut-in pressure decay during DFIT (Diagnostic Fracture Injection Testing), as outlined in Chapters 5 and 6.

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Research Interests

Energy extraction related to:

- Exploration
- Drilling
- Completion
- Stimulation
- Production

John is a USTAR Associate Professor in the Department of Chemical Engineering at the University of Utah. He holds a Ph.D. in Civil Engineering from the University of Toronto, Canada (1980). His experience extends to petroleum service and technology companies. He worked for Dowell Schlumberger in Denver, Tulsa and Houston; later, with TerraTek in Salt Lake City, Advantek International in Houston, and ASRC Energy Services in Anchorage. He has worked on coalbed methane recovery, mechanical properties determinations, produced water and drill cuttings reinjection, as well as casing design issues related to compaction. John's recent work has focused on optimized gas production from shales and unconsolidated formations.

Shale Gas Phase 2

The three key elements for a successful low permeability reservoir play are gas-in-place, heterogeneities providing permeability in excess of the matrix, and successful stimulation. EGI has been addressing the first of these directly, performing fundamental measurements to indicate the formation and reservoir parameters that govern recoverable gas-in-place. Storage mechanisms (adsorption, compressibility, and dissolution) were determined as functions of gas species, pressure history (reliable lost gas measurements), moisture content, and mineralogy. Without reliable gas-in-place forecasts, and the ability to identify desirable settings in advance, play development is expensive and prolonged.

Stimulating Low Permeability Reservoirs

In any low permeability formation – shale, tight sands, oil shale, geothermal, etc. – effective stimulation entails developing extensive, interconnected fracture systems with adequate conductivity. This effort leverages from projects awarded to the Department of Chemical Engineering by RPSEA for development of new generation simulators. This simulation methodology interrelates formation heterogeneity (stresses, fractures, high permeability streaks) with simulations of the growth of fracture systems during injection; and represents production from this specific, complex fracture network – next generation integrated geologic and production simulation.

Enhanced Geothermal Systems

EGI's geothermal group is engaged in development work for Enhanced Geothermal Systems. Hydraulic injection (either above or below fracturing pressure) is one method to develop an enhanced fracture system, providing surface area for exposure of liquids to elevated temperature en route to producing wells and subsequent conversion to usable energy. The key element of these systems is that they are engineered. Fractures are created with optimal morphology by exploiting the *in-situ* stresses and natural heterogeneity – engineering fracture growth for heat extraction.

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