A MAGNITUDE-BASED CALIBRATED DISCRETE FRACTURE NETWORK METHODOLOGY

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INTRODUCTION

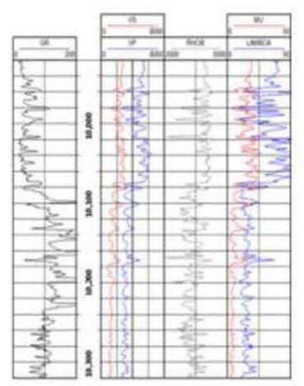
Effective propped fracture half-lengths following a typical hydraulic fracture stimulation of a wellbore can be difficult to quantify. Therefore, new modeling techniques must be developed to improve estimates of proppant distribution in a formation to understand the spatial extent of proppant-filled fractures. The distribution of propped and unpropped fractures can then be statistically analyzed to determine the productive stimulated rock volume (SRV) and constrain key field development parameters such as wellbore and stage spacing as well as vertical containment of proppant placement.

METHOD

A magnitude-based calibrated Discrete Fracture Network (DFN) methodology based on microseismicity induced during stimulation of a wellbore has been developed that incorporates magnitude of the event (and associated microseismic moment (*M*)), rock rigidity (μ), injected fluid volumes (*Vi*), and fluid efficiency (η). Calculated fracture volumes (*Vf*) are then scaled to account for any missing portion of the seismic population. The calibrated DFN can then be filled with the measured injected proppant volume on a stage-by-stage basis by initially filling fractures nearest the wellbore and systematically filling fractures outward from the wellbore until all proppant volumes have been depleted.

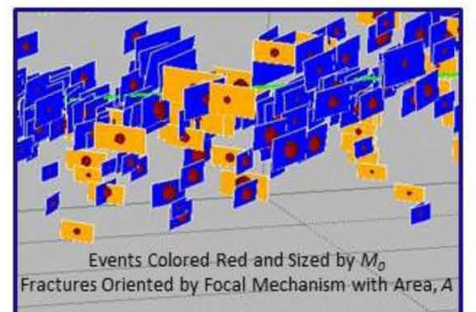
Fundamentally, for every microseismic hypocenter, fracture area (*A*) $=M/\mu\delta$ where δ is displacement along the slip plane. Since δ is not directly measured, it is initially estimated using an empirical relation as a function of *M* and corrected using a scaling factor (*k*) where $k=Vf/[(Vi)\eta]$. The scaling factor is calculated by comparing *Vf* to $(Vi)\eta$ following a hydraulic fracture stimulation of an individual stage where the sum of the seismic moments is greatest (compared to all stages monitored) and energy released is only associated with fluid injection (e.g. not tectonic activity).

Rock Rigidity, μ

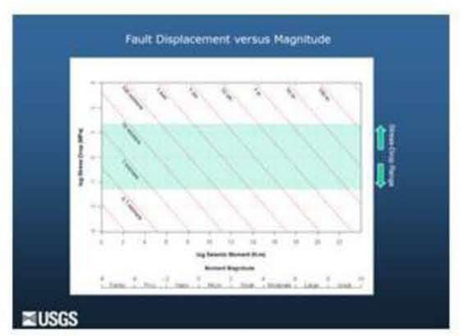


$M_0 = A\mu\delta$

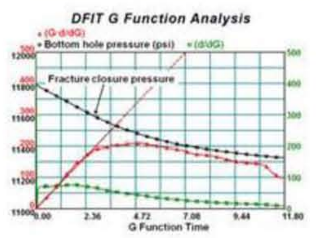
$\Delta V_f = A * \Delta u = (\Delta V_{inj})\eta k$



Displacement, δ



Fluid Efficiency, η



Workflow
1. Derive Fracture Area
   - Use magnitude from mPGV
   - Determine rigidity from logs, displacement from published tables
2. Derive Fracture Aperture
   - Use area calculation, fluid efficiency, and known injected volumes to estimate aperture

Injected Volume, ΔV_{inj}

Clean Volume + Proppant Volume
Propped Volume assumes 100 lbs = 1ft³

THEORY

The seismic moment (M_0), which is defined as $A\mu\delta$ (*A* is area of the slip plane, μ is shear modulus, and δ is average displacement along the slip plane), is a fundamental equation that relates seismic source parameters to actual measured variables (Kanamori, 1977).

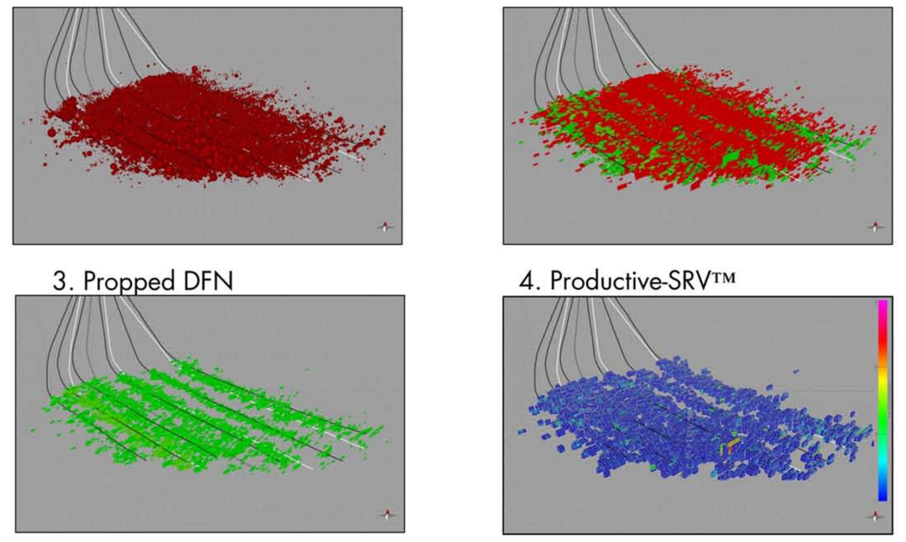
Measurement Parameters:

- Seismic Moment M_o
- Rock Rigidity μ
- Fluid Efficiency η
- Injected Fluid Volume V_i,
- Displacement δ
- *Microseismic hypocenter Focal Mechanism*

McGarr (1976) related total detected seismicity to injected volumes assuming that the change in volume is completely accommodated by the seismic failure using the equation $\sum M_0 = k\mu|\Delta V_i|$ where *k* is a scaling factor ranging from 0 to 1 accounting for fluid leaking off into the formation. This leakoff volume can be determined from a Diagnostic Fracture Injection Test (DFIT) by $\eta = \frac{V_f}{V_i}$ ranging 0-1, where a value of 1 indicates that all of V_i is reflected by an identical fracture volume (V_f) and when η is equal to 0, all of the fluid is assumed to leakoff into the formation.

WORKFLOW

- Estimate fracture aperture Δu empirically by related to the length of the fracture using a power law relation (e.g. Vermilye and Scholz, 1995).
- Relate $V_f = A\Delta u = V_i\eta k$, where *k* in this case accounts for any undetectable seismic failure.
- Assume an aspect ratio of 0.5 (fracture height, *h*, is 0.5*L* where *L* is the length of the fracture).
- Calculate k on a stage by stage basis.
- Select a calibration stage as the stage with the highest *k* value (i.e., V_f is closest in value to V_i), excluding events associated with tectonically induced fractures.
- Refine displacement estimate using $d_{new}=dk^{4/5}$
- Recalculate fracture geometry parameters
- Model the extent of the Propped DFN
- Estimate the Productive SRV

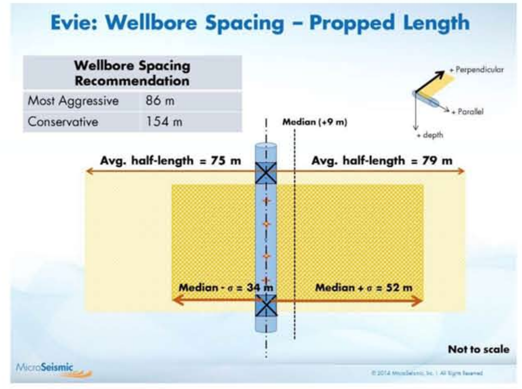


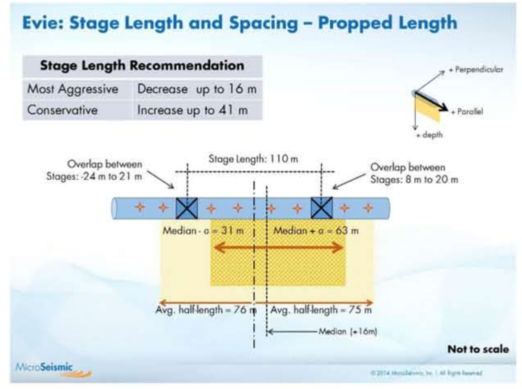
APPLICATION AND COMPLETIONS DIAGNOSTICS

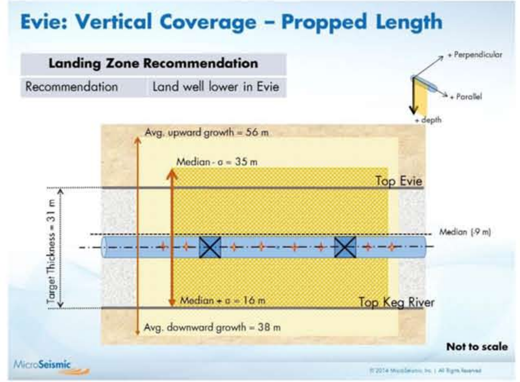
The fracture distributions are defined by the statistical values (minimum, maximum, median, average, standard deviation) are broken up by the:

- perpendicular horizontal
- parallel horizontal
- perpendicular vertical components

of the fracture distances with respect to their corresponding stage center. These distributions can be used to determine the most appropriate wellbore and stage spacing as well as the vertical containment of the proppant.







- For example, when evaluating wellbore spacing, it is important to look at the standard deviation (since the average and median values are close to 0) associated with the perpendicular component of the propped as well as the entire fracture distribution

DISCUSSION

This simple model accounts for limitations in measureable data and the missing seismic population. Improved estimations of δ and η as well as improved microseismic detection algorithms will improve results. Pressure dependent η can also be incorporated into the methodology since the bottom-hole pressure at the time of microseismic event occurrence can be calculated. Using this technique as part of an integrative analysis, the distribution of proppant deposited in a formation following a hydraulic-fracture stimulation can be well constrained to yield good estimates and the associated proppant-filled half-lengths are typically much less than the half-lengths associated with the full extent of the microseismicity.

MicroSeismic
Passive Monitoring, *Active Listening*