

On Some Fluid-Based Monitoring Tasks Within the EU Project FracRisk (2015–2018)

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ABSTRACT

The EU project FracRisk (June 2015 – May 2018) set out to provide decision support tools for dealing with fracking-related hazards (McDermott and Sauter 2014). It relies on top-down approaches to FEP (feature, event, process) screening in order to reduce the risk assessment job to a small set of relevant scenarios, and on efficient, FEP-overriding source/pathway/receptor (SPR) compartmentalizing (Sauter 2012). Though long-established in the realm of radioactive waste management, FEP concepts prove of limited value when applied to shale-gas (SG) exploitation, whose main environmental footprint stems from low intrinsic productivity (need to frequently re-enter the wells), rather than from so-called hazards. Thus viewed, SG development is neither a significant-risk technology, nor the game changer. Artificial and natural tracers may serve several purposes in the SG context: besides assessing un-/desired transport connectivity between S and R, or within S and P, and quantifying fluid/solute/mineral mixing/dilution/transfer within/between S and P, a more significant contribution is expected from tracers in measuring productivity-critical transport parameters within S. However, parameter inversion from measured tracer signals poses great challenges in single-well settings (as used for SG), where flow-field reversal invalidates the equivalence between tracer residence times and fluid transport parameters. Recent tracer-technological innovations address inflow profiling, proppant imaging, proppant-embedded tracers; yet, to date, not a single example is known of a tracer-based estimation of a SG frac-related parameter. We propose new type-curve sets for assessing parameter sensitivity, and, where applicable, inverting tracer signals in terms of production-critical parameters (frac volume, fissure aperture and spacing, fluid-rock interface area), for liquid-/gas-phase tracers detectable uphole during backflow/production (no downhole instrumentation required). Most of these findings prove applicable to geothermal reservoirs as well, especially the EGS type involving multiple artificial fractures.

1. RATIONALE

Jacobs (2016) regards the downturn on SG production as ‘the stress test’ for hydraulic fracturing modelers, while Walser (2016) regards it as a kind of stress test also for the D&C industry. Both these philosophies assume re-fracturing were the key to overcoming the current downturn on SG prices, and the primary goal of re-fracturing were (fig. 1, fig. 2): minimize fissure spacing (a), maximize frac or fissure aperture (w) and/or length (L). Both regard these parameters as a primary target of fluid-based monitoring, alongside with the frac-resolved inflow profiling.

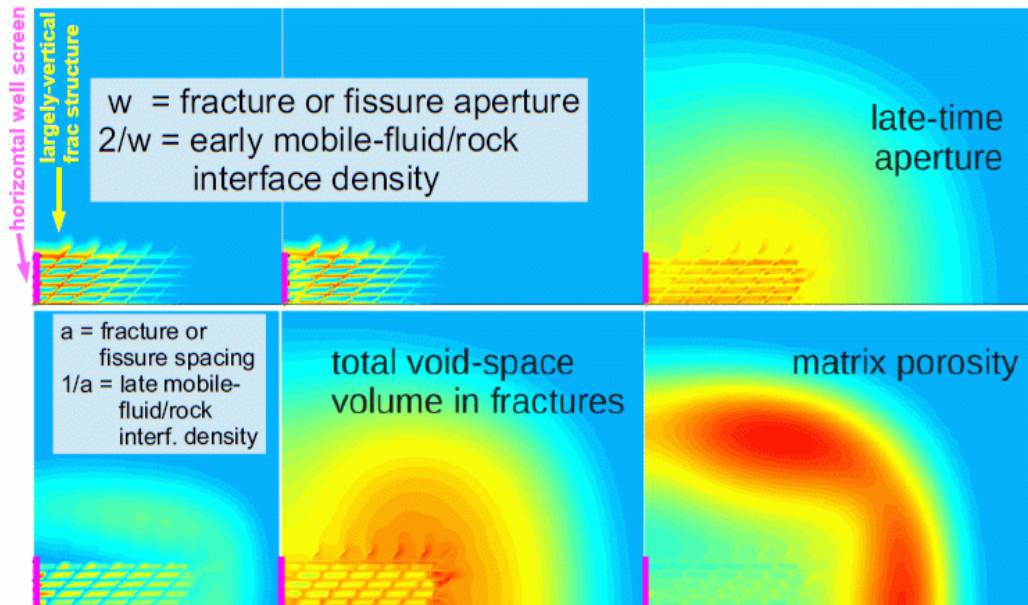


Figure 1: Transport parameters, and parameter sensitivity regimes expectable for tracer signals in single-well tests.

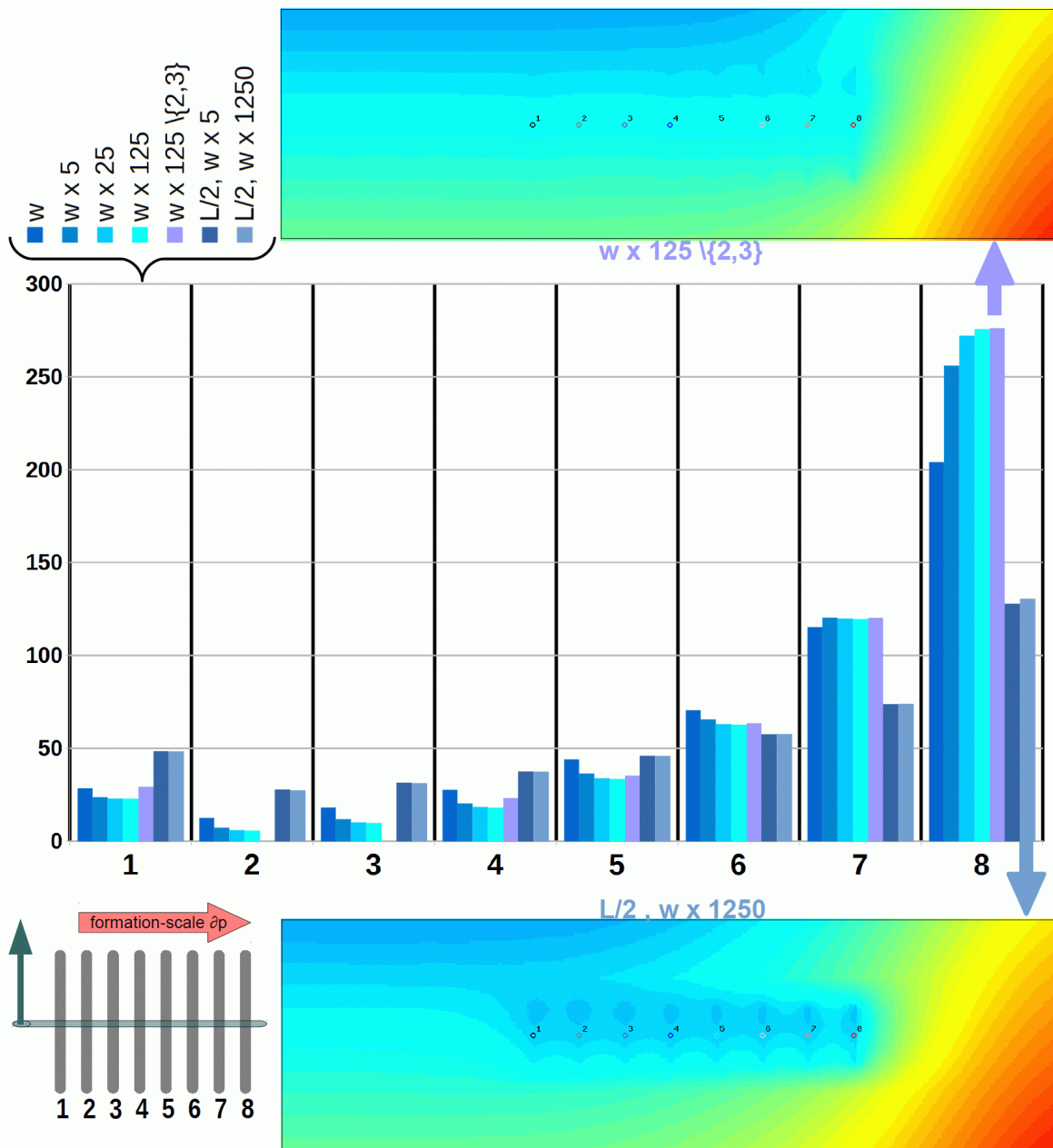


Figure 2: In advanced depletion stages, with flow regime transition from frac-scale diffusion-limited to formation-scale pressure-driven, ‘refrac’ can no longer augment inflow.

However, as depletion goes on, the flow regime will change from (frac-scale) diffusion-limited to (formation-scale) pressure-driven; onset of the latter (fig. 2) means re-fracturing can no longer significantly augment the inflow contribution of any fracture (neither via w , nor via L), except for the most remote ones.

To assist in predicting this transition, we attempt to develop a type-curve framework for assessing parameter sensitivity, and, where applicable, inverting early and mid-late tracer signals in terms of these production-critical parameters (frac volume, fissure aperture and spacing, fluid-rock interface area density), for liquid- and gas-phase tracers detectable uphole during backflow and production (no downhole instrumentation required).

2. FLUID-BASED MONITORING: ARTIFICIAL TRACERS

Artificial and natural tracers may serve several purposes in the SG context: besides assessing un-/desired transport connectivity between S and R, or within S and P, and quantifying fluid / solute / mineral mixing / dilution / transfer within or between S and P, a more useful contribution is expected from artificial tracers in measuring productivity-critical transport parameters within S (frac area, fracture and fissure spacing, fluid-rock interface area density, among other). However, parameter inversion from measured tracer signals poses great challenges in single-well settings (as used for SG), where flow-field reversal invalidates the equivalence between tracer residence times and any of a reservoir’s ‘extensive’ (i. e., volume- or area-related) parameters (cf. more detailed discussion in Ghergut et al. 2013). Recent tracer-technological innovations address inflow profiling, proppant imaging, proppant-embedded tracers; yet, to date, not a single example is known of a tracer-based estimation of a frac-related parameter in the SG context.

Within the EU project FracRisk (work package WP6 led by the Geophysics Group of TU Vienna), we attempt to develop a type-curve framework (fig. 3) for assessing parameter sensitivity, and, where applicable, inverting tracer signals in terms of production-critical parameters (frac volume, fissure aperture and spacing, fluid-rock interface area density), for liquid- and gas-phase tracers detectable uphole during backflow and production (no downhole instrumentation required), with focus on early and mid-late tracer signals wherever applicable.

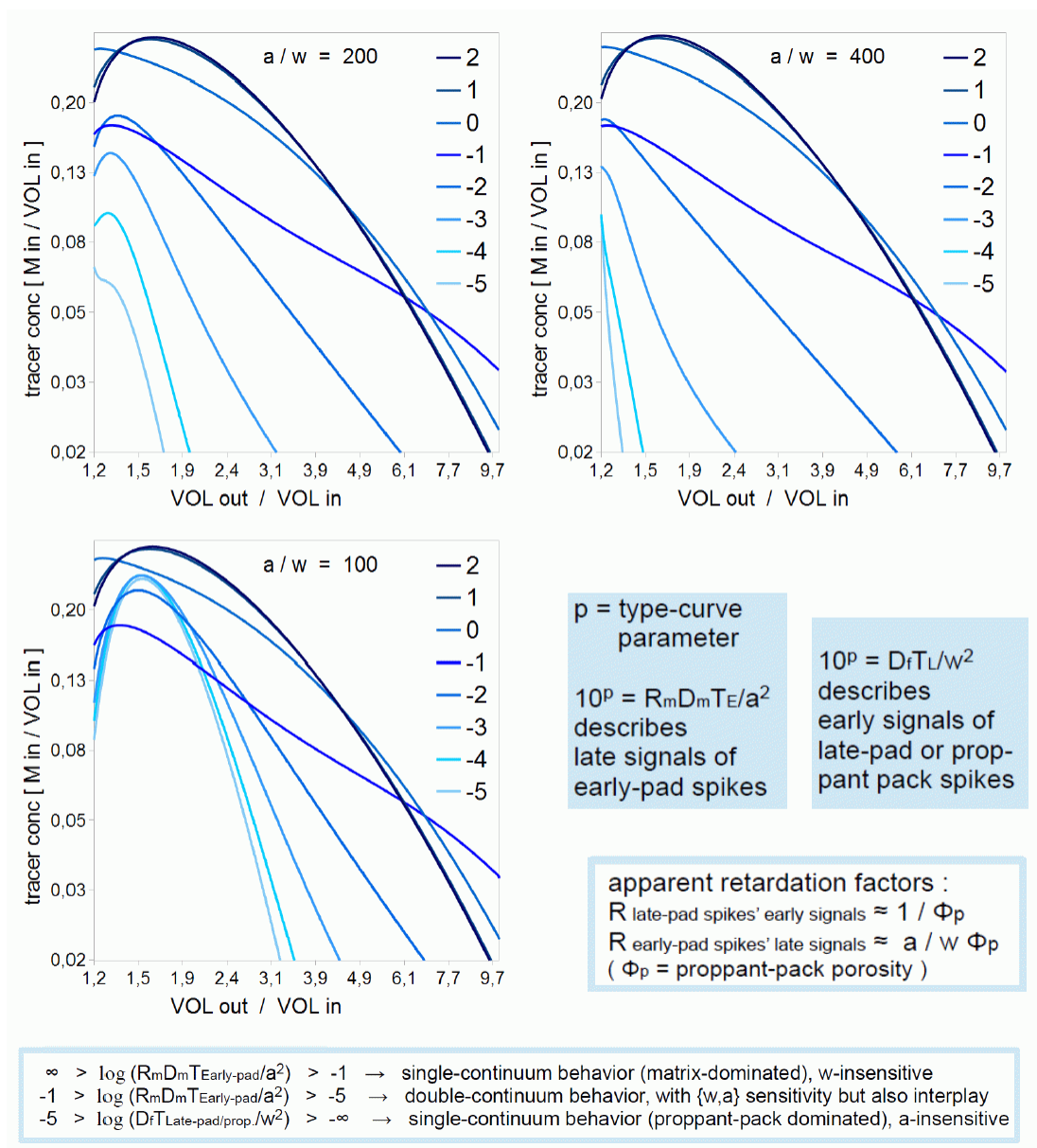


Figure 3: Tracer signal type-curve families, and parameter sensitivity regimes.

Having identified at least three distinct parameter sensitivity regimes (as listed at the bottom of fig. 3), we propose a four-spike scheme for tracer additions during pad and proppant-mixture injections, respectively: early pad spike for estimating a , late pad spike for estimating a/w , early proppant-mixture spike for estimating proppant-pack porosity Φ_p , late proppant-mixture spike for constraining w estimation (reducing the parameter interplay between non-/advective processes). Parameter inversion is greatly facilitated by the use of different tracer species, yet the four distinct regimes can, in principle, also be achieved by merely varying the size of T_p (solely chaser-steered spiking design), i. e., by the ‘pulsed’ addition of a single tracer species, whereby the pulse shape itself plays no special role in parameter estimation.

Of all target parameters, matrix porosity appears most recalcitrant to a tracer-based estimation (recall fig. 1 in the first section), unless reactive tracers with very special threshold and/or partitioning properties would become available (so far, steerable-delay in-situ release has been achieved for casing- or proppant-embedded, but not for matrix-pervading tracers). Natural tracers (Wiegand and Sauter 2016) as well as SNL and other non-fluid-based monitoring techniques may also aid in reducing the ambiguity of tracer signal inversion (Caffagni and Bokelmann 2016). These are currently being considered for further development within work packages WP3 and WP6 of the EU project FracRisk.

3. KNOWLEDGE TRANSFER? SG VERSUS EGS RESERVOIR CHARACTERIZATION

Geothermal systems, in turn, perform ‘pressure-driven’ throughout (recall fig. 2 in the first section), and their inner-vs.-outer frac inflow imbalances (in petrothermal systems) can be compensated by a ‘facing opposite’ (Jung 2013, Krug and Tischner 2013) placement of production pump and injection wellhead, respectively (which is not possible for SG). The type-curve approach for artificial-tracer test design and inversion remains largely applicable for single-phase (liquid-only) geothermal reservoir development involving artificial fractures (either petrothermal, or aquifer-type EGS), with some limitations regarding the availability of suitable tracer species, yet with the advantage of virtually unlimited signal ‘tail’ duration (cf. Ghergut et al. 2016). EGS in Central Europe, however, mostly face problems far more intricate than just ‘optimizing’ fracture system (a, w, L) design.

The EU project FracRisk (June 2015 – May 2018) set out to “*improve the understanding of potential environmental impacts associated with the exploration and exploitation, through fracking, of significant shale gas reserves found throughout Europe, and provide decision support tools for dealing with certain fracking-related hazards*” (McDermott and Sauter 2014). It relies on top-down approaches to FEP screening in order to reduce the risk assessment job to a small set of relevant scenarios (Sauter et al. 2012; Lange et al. 2012), as well as on efficient, FEP-overriding source / pathway / receptor compartmentalizing (fig. 4).

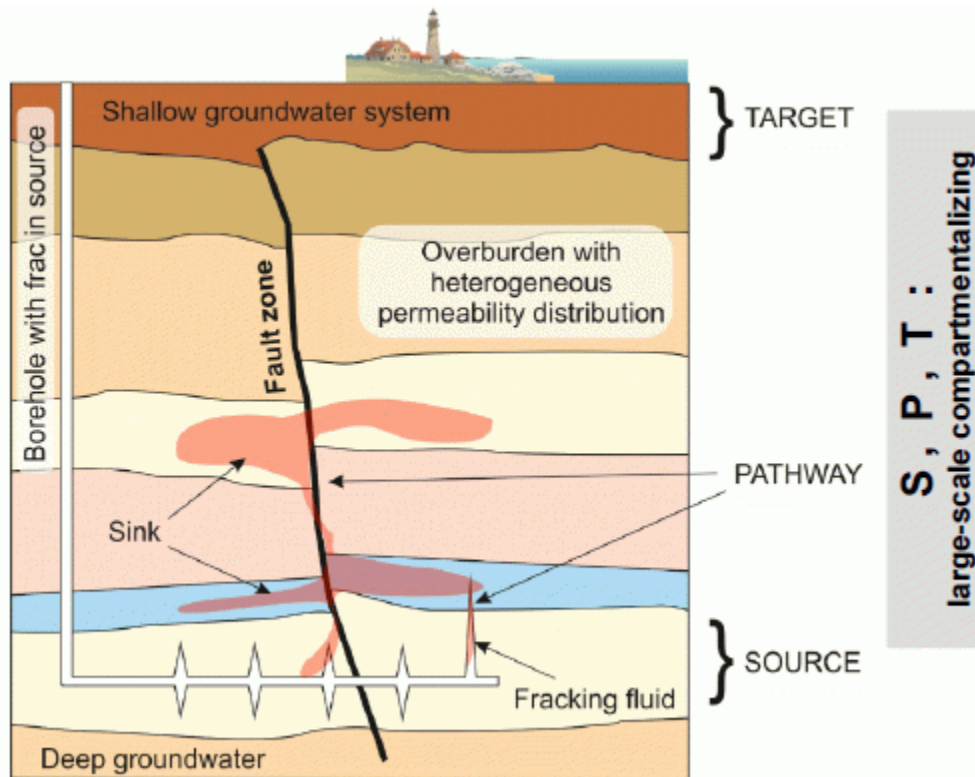


Figure 4: Source / pathway / target or receptor compartments considered within EU project FracRisk for dealing with certain fracking-related hazards (reproduced from Sauter et al. 2013, McDermott and Sauter 2014).

Though long-established in the realm of radioactive waste management, FEP concepts prove of limited value when applied to SG exploitation, whose main environmental footprint stems from its rather poor intrinsic productivity (need to frequently re-enter the wells etc.), rather than from so-called “hazards”. From this perspective, SG development is neither a significant-“*risk technology*”, nor “*the game changer*”. Very much like in the EGS realm, the true ‘game changer’ may emerge from improving our various non-/fluid-based tools (Caffagni and Bokelmann 2016) for reservoir characterization.

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