

A methodology to detect and locate low-permeability faults to reduce the risk of inducing seismicity of fluid injection operations in deep saline formations



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ABSTRACT

Fluid injection in the subsurface has significantly increased over the last decades. Since fluid injection causes pressure buildup, reducing effective stresses, shear failure conditions may eventually occur, inducing microseismic and seismic events. Anticipating felt induced earthquakes that may be triggered in undetected faults is crucial for the success of fluid injection projects. We propose a methodology to detect and locate such low-permeability faults to reduce the risk of inducing felt seismic events. The methodology consists in using diagnostic plots to identify the divergence time between the logarithmic derivative of overpressure evolution measured in the field and the one that would correspond to an aquifer including the previously identified heterogeneities. We apply the proposed methodology to water and CO₂ injection through a horizontal well in a confined aquifer that has faults parallel to the well. We numerically obtain type curves that allow locating low-permeability faults once the divergence time is determined from the logarithmic derivative of overpressure for both water and CO₂ injection. Furthermore, we illustrate how to apply the methodology to detect multiple low-permeability faults. To perform a proper pressure management based on fault stability analysis to minimize the risk of inducing felt seismic events, the proposed methodology should be complemented with other multidisciplinary tools. This methodology can be extended to other geological settings and be used in several fluid injection applications.

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1. Introduction

Fluid injection in deep saline formations (deeper than 1 km) is becoming more frequent because: (i) geologic carbon storage and geothermal energy are being considered as a means of mitigating climate change (Hitchon et al., 1999), (ii) seasonal natural gas storage and underground compressed air energy storage are being used for strategic reasons to ensure energy supply (McCartney et al., 2016), and (iii) the wastewater resulting from hydrofracturing operations to extract hydrocarbons like shale gas and shale oil is being injected in deep saline formations (Ellsworth, 2013). All these activities involve fluid injection in the subsurface, which induces a fluid pressure buildup that is usually accompanied

by induced microseismicity (NAS, 2012; IEAGHG, 2013). Induced microseismicity is usually of very low magnitude, typically less than magnitude 2, and thus, it is not felt on the ground surface (Rutqvist et al., 2016). However, some induced seismic events may be large enough to be felt by the local population and sometimes even cause damage to structures and infrastructures (Ellsworth, 2013; Gambolati and Teatini, 2015).

The occurrence of felt induced seismicity could jeopardize dams and nuclear power plants and has a very negative impact on public perception because it causes discomfort, nuisance and fear among the local population (Oldenburg, 2014). One of the largest seismic events induced by wastewater injection occurred at Prague, Oklahoma, USA, on November 6, 2011, having a magnitude 5.7 (Keranen et al., 2013). This earthquake caused some damage, including injuries and the collapse of several buildings (Yeck et al., 2016). The consequent loss of public acceptance may usually end up with the cessation of injection activities. For example, the geothermal projects of Basel and Sankt Gallen, both in Switzerland, were halted

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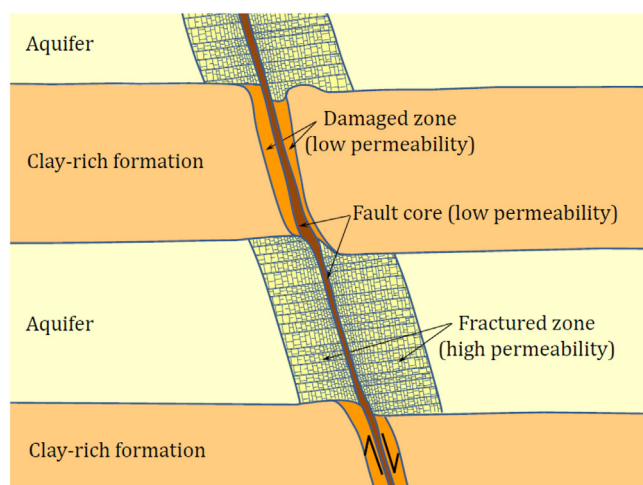


Fig. 1. Schematic representation of the fault architecture and permeability distribution in a sequence of alternating aquifers and clay-rich formations. The core of the fault is of low permeability due to reduced grain size and porosity as a result of friction. Rocks become damaged on both sides of the fault core, but the geo-mechanical response of stiff aquifers and ductile clay-rich formations are significantly different. While aquifers tend to fracture, enhancing permeability, clay-rich formations are more ductile and instead of fracturing undergo localized deformation that decreases permeability.

during their initial phase, prior to operation, because earthquakes of magnitude between 3 and 4 were induced during the stimulation of the wells (Häring et al., 2008; Breede et al., 2013; Király et al., 2014). Another example is the offshore Castor Project of seasonal natural gas storage in Spain. This project was cancelled after a sequence of induced seismic events that were felt by the local population. The induced events had a maximum magnitude of 4.3 and occurred after the first 15 days of gas injection (Cesca et al., 2014). Taking into account that each well costs several millions of dollars, if a project is closed before its operation, the economic losses are huge. Thus, felt induced seismicity should be avoided.

Felt induced seismicity usually occurs in pre-existing faults. While major faults are usually detected and their location is relatively well known, minor faults cannot, in general, be identified with conventional geophysical methods due to their small offset (Mazzoldi et al., 2012). Minor faults may have several hundreds of meters in length, so they may not completely cross thick caprocks, but they have enough area to induce earthquakes ranging from magnitude 2–4 (Mazzoldi et al., 2012). Unfortunately, since the location of minor faults is not known a priori, pressure relief measures, like drilling pumping wells, to decrease excessive overpressure, cannot be envisaged prior to injection around minor faults (Birkholzer et al., 2012). However, if minor faults could be detected somehow during injection, pressure management could be applied to both major and minor faults to avoid inducing felt seismic events.

Fault zone architecture can give a clue regarding how faults could be detected (Fig. 1). Faults usually present a core and a damaged zone (Caine et al., 1996). The magnitude of the hydraulic properties of the fractured zone and the core can vary by several orders of magnitude depending on the host rock lithology, fault dimensions and accumulated shear displacement (Takahashi, 2003; Crawford et al., 2008; Egholm et al., 2008). In aquifers, which have low clay content and are usually stiff, the damaged zone is highly fractured and has a higher permeability than that of the intact rock (Cappa and Rutqvist, 2011a). In contrast, the core is characterized by a low porosity and reduced grain size due to friction, which reduces permeability (Billi et al., 2003; Bense and Person, 2006). Thus, the fault core will usually have a lower permeability

than that of the aquifer and thus, the fault may act as a barrier to flow across it.

On the other hand, the higher permeability of the damaged zone in the aquifer does not have continuity in the vertical direction. Actually, the vertical permeability of the damaged zone in the caprock is orders of magnitude lower than in the aquifer due to particle breakage that occurs in zones of localized shear slip in ductile clay-rich formations (Takahashi, 2003; Egholm et al., 2008; Nussbaum et al., 2011; Laurich et al., 2014). Thus, the along fault transmissivity is smaller than the across fault transmissivity in minor faults. As a result, pressure cannot be significantly released due to fluid flow along the fault in the vertical direction (Tillner et al., 2016). In view of the fault architecture and permeability distribution, we conjecture that faults can be detected by monitoring fluid pressure and detecting deviations from the overpressure evolution that would correspond to an aquifer without faults.

The analysis of fluid pressure evolution together with the derivative of the fluid pressure with respect to the logarithm of time, known as diagnostic plots (Bourdet et al., 1983), is often used in well-test analysis to detect aquifer heterogeneities (Gringarten, 2006; Hosseinpour-Zonoozi et al., 2006; Renard et al., 2009). Examples of idealized heterogeneities as diverse as a cylinder or a linear strip of permeability different from the rest of the aquifer can be identified with the aforementioned analysis (e.g., Wheatcraft and Winterberg, 1985; Butler, 1988; Butler and Liu, 1991, 1993). Such heterogeneities are only detectable for a limited time. Afterwards, the fluid pressure evolution coincides with the evolution in a homogeneous aquifer. Similarly, the slope of fluid pressure as a function of the logarithm of time is proportional to the effective permeability of the region affected by the pressure perturbation cone in heterogeneous aquifers (Meier et al., 1998; Sánchez-Vila et al., 1999). By contrast, the effect of a linear boundary, acting either as a constant pressure or as a no-flow boundary, is more persistent, even for linear heterogeneities of non-zero permeability, and changes the slope of fluid pressure evolution with the logarithm of time. This change in the slope of fluid pressure or of its derivative is usually used to detect faults in petroleum engineering (e.g., Gray, 1965; Matthews and Russell, 1967; Earlougher, 1977; Lee, 1982; Sageev et al., 1985; Horne, 1995; Maghsood and Cinco-Ley, 1995; Sahni and Hatzignatiou, 1995; Aydinoglu et al., 2002; Charles et al., 2005).

In presence of sealing faults, application of superposition principle in terms of image well technique results in zero-slope pressure derivative that has been widely used for locating faults (Horner, 1951). However, the image method fails when the fault is not a full barrier to flow, which is generally the case. Therefore, a general approach to fault characterization requires accounting for fault transmissivity. Such consideration involves solving the diffusivity equations coupled at the fault over the x - y plane. Analytical approaches to solve the coupled equations were developed in the literature using different techniques, including integral transforms (Bixel et al., 1963; Yaxley, 1987; Ambastha et al., 1989), Green's function (Raghavan, 2010), and wave transform (Oliver, 1994). These analytical solutions were casted in the form of diagnostic plots for characterization of faults.

The use of diagnostic plots has also been extended to two-phase flow of gas or oil and water, but neglecting gravity effects (Perrine, 1956; Martin, 1959; Raghavan, 1976; Kamal and Pan, 2011). However, carbon dioxide (CO_2) is buoyant and thus, gravity effects should be included in diagnostic plots analysis. Also, two-phase flow models are highly dependent on the choice of the relative permeability curves, which may introduce significant uncertainty in the analysis. Unlike those models, the two-phase CO_2 -brine system in this work is approximated by an equivalent single-phase model to simplify the pressure analysis. Furthermore, previous methodologies were not focusing on providing the required information to

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