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.

Keywords: fluid injection; pressure buildup; diagnostic plots; induced seismicity; dimensional analysis; numerical models

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 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 to 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 (Figure 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.

Figure 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 geomechanical 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.

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 pressure management in order to anticipate potential felt induced seismicity.

The aim of this study is to present a methodology based on the monitoring of the pressure buildup using diagnostic plots to detect and locate faults and thus provide predictive capability to apply the necessary mitigation measures to avoid inducing felt seismic events. First, we briefly explain diagnostic plots and describe the concept for detecting and locating faults using fluid pressure evolution measurements and its derivative. Next, we apply the proposed methodology to a particular case, consisting of an aquifer in which either water or CO_2 is injected through a horizontal well. Finally, we illustrate the applicability of the

methodology for two faults and discuss how it may be extended to more complex geological settings.

2. METHODS

2.1. Diagnostic Plots

In well-test analysis, diagnostic plots enable one to highlight the divergence of a monitored physical parameter and identify the most appropriate conceptual model (Renard et al., 2009). Diagnostic plots show pressure change caused by fluid pumping/injection and its logarithmic derivative as a function of time on log-log plots. If fluid pressure is evolving for some reason before injection, pressure change should be calculated as the measured pressure minus the pressure that the aquifer would have at that moment taking into account the pre-existing tendency. The aim of using these plots here is to identify whether pressure at an observation well diverges from the expected evolution of an aquifer that includes the already identified heterogeneities and if they diverge, to determine the divergence time (see Equation (2) for the definition of divergence time).

The disturbance caused by a fault can be slight and hardly identifiable by looking only at the fluid pressure evolution. To improve fault detection, the logarithmic derivative of the pressure change is used to determine the divergence time because it is more sensitive to tendency changes (Renard et al., 2009). Taking the derivative of the pressure retains only the time-dependent coefficients in the corresponding fluid flow models and therefore, it is more sensitive to the time at which a deviation from an expected behavior occurs. As a result, the logarithmic derivative in the presence of a fault diverges from that corresponding to an aquifer without the fault earlier than fluid pressure evolution (Figure 2). Thus, using the logarithmic derivative to identify and locate faults can provide enough time to decision makers to evaluate if mitigation measures should be carried out in order to avoid excessive

overpressure that could induce seismicity. The logarithmic derivative of the pressure change can be calculated as (Bourdet et al., 1983; Renard et al., 2009)

$$\frac{\partial p}{\partial \ln(t)} = \frac{\Delta p}{\ln(t+\Delta t) - \ln(t)} \quad (1)$$

where Δp [$\text{ML}^{-1}\text{T}^{-2}$] is the pressure change that occurs in the interval of time Δt [T], p [$\text{ML}^{-1}\text{T}^{-2}$] is fluid pressure and t [T] is the time since the beginning of pumping/injection. The units of the logarithmic derivative of fluid pressure are also of pressure, i.e., [$\text{ML}^{-1}\text{T}^{-2}$], because $\frac{\partial p}{\partial \ln(t)} = t \frac{\partial p}{\partial t}$. Hereafter, we will refer to the logarithmic derivative of pressure change just as derivative of pressure change. Pressure change can be either positive (overpressure) or negative (drawdown). Since fluids are injected in the applications we are interested in, overpressure occurs and thus, we will refer to overpressure in the remaining of the paper. Nevertheless, if fluid were pumped, the same procedure would apply to drawdown.

Figure 2: Diagnostic plot of overpressure evolution induced by fluid injection in a homogeneous aquifer and in the same aquifer, but containing a low-permeability fault. The time at which the logarithmic derivatives of overpressure diverge is defined as the divergence time, t_{div} , which occurs significantly earlier than the divergence in the overpressure evolution.

2.2. The concept for reducing the risk of induced seismicity

To reduce the risk of inducing felt seismic events, we propose using diagnostic plots to identify the presence and estimate the location of low-permeability faults. By plotting in the same diagnostic plot the curves corresponding to an aquifer containing a fault and the same aquifer but without the fault, the resulting curves will diverge at a certain moment. Note that site characterization should be performed previously to the beginning of injection to have an estimate of the aquifer transmissivity and storage coefficient (Vilarrasa et al., 2013b). When the pressure perturbation front reaches a fault, the fault will disturb the flow pattern and cause additional overpressure in the aquifer. This effect is readable in the diagnostic plots by an increase of the overpressure and its derivative compared to the aquifer without the fault. The derivative of the overpressure will diverge earlier (in the order of days for storage in extensive sedimentary basins) than overpressure and the time at which the two derivative curves detach from each other gives the divergence time, t_{div} (Figure 2). The divergence time is defined as the time at which

$$\frac{\partial p}{\partial \ln(t)}(measurements) - \frac{\partial p}{\partial \ln(t)}(no\ fault) \geq threshold \quad (2)$$

where $\frac{\partial p}{\partial \ln(t)}(measurements)$ is the derivative of the pressure change measured in the field, $\frac{\partial p}{\partial \ln(t)}(no\ fault)$ is the derivative of the pressure change corresponding to the case with no fault and $threshold$ is a certain threshold that may be defined according to the precision of the fluid pressure measurements and the fluid injection project.

The methodology that we define to detect and locate low-permeability faults is summarized in Figure 3. First, a well test should be performed to characterize the hydraulic properties of the aquifer. A numerical model should be built based on the geometry of the injection site, using the properties derived from the well test. If any kind of heterogeneity is identified previously to injection, such as major faults, they should be incorporated in the

model. Since field characterization tests are of limited duration (up to a few days), the hydraulic characterization information that they provide corresponds to a scale that is much smaller than the scale involved during operation of injection sites. Thus, a continuous characterization by analyzing the pressure evolution during long-term fluid injection is crucial to gain information on heterogeneities placed in the far field.

Figure 3. Workflow to detect and locate low-permeability faults during fluid injection operations.

The fluid pressure evolution measured in the field and its derivative will be compared against the expected evolution calculated with the numerical model of the site including previously identified heterogeneities. If a deviation in the overpressure derivative larger than a certain threshold occurs (recall Equation (2)), the divergence time will be determined. Then, the location of the low-permeability fault can be estimated from the divergence time. The number of observation wells that will be present in fluid injection operations in deep saline formations will certainly be limited due to the high cost of perforating wells at such depths. In

general, two observation wells, in addition to the injection well, should be enough to determine the location of a fault. Nevertheless, the larger the number of observation wells, the higher the reliability of the location and orientation of the fault.

Once a fault has been detected and located, it should be incorporated in the numerical model. Next, the permeability of the fault will be calibrated to reproduce the fluid pressure measurements. This calibration should be performed rapidly because a new prediction of the overpressure evolution taking into account the detected low-permeability fault has to be done. This updated prediction of the overpressure evolution should be used to evaluate fault stability analysis (using the stress state, which should be measured prior to injection, together with the estimation of the strike, dip and strength of the detected fault, including the uncertainty in these parameters as well) (e.g., Moeck et al., 2009; Vilarrasa et al., 2013b; Pereira et al., 2014). To perform this stability analysis, multidisciplinary characterization (e.g., 3D seismics) and monitoring techniques (e.g., microseismic monitoring) should be combined to estimate the dip, dimensions and strength of faults.

Pressure management becomes important at this stage. If the fault stability analysis reveals that the maximum sustainable injection pressure is being approached, mitigation actions should be carried out to decrease the overpressure around the fault. To achieve this pressure relief, a good practice would be to design monitoring wells such that resident brine can be pumped from them. At this stage, the pressure derivative of the field measurements should be compared against the pressure derivative of the updated numerical model in order to detect the potential presence of more faults. This process should be repeated until the end of fluid injection in order to reduce the risk of inducing felt seismic events.

2.3. Application of the methodology to a specific case

To illustrate the applicability of this methodology that aims at reducing the risk of inducing felt earthquakes, we model fluid injection through an infinite horizontal well in a confined aquifer which has homogeneous and isotropic properties, but that may contain one or two low-permeability undetected faults parallel to the injection well (Figure 4). The injected fluid can be either the same fluid as that present in the aquifer or can form another phase, e.g., CO₂. The flow rate is assumed to be constant and adjusted to induce an overpressure below the initial estimate of the maximum sustainable injection pressure, thus avoiding geomechanical stability issues (Rutqvist et al, 2007).

Figure 4. Schematic representation of the geometry of the application, in which a fluid is injected in a confined aquifer through a horizontal well at a constant flow rate. Fluid pressure buildup may be affected by low-permeability faults, which may act as flow barriers, causing an additional overpressure on the side of the fault closer to the injection well.

For the general case of two-phase flow, mass conservation of each phase is given by (Bear, 1972),

$$\frac{\partial(\phi S_{\alpha} \rho_{\alpha})}{\partial t} + \nabla \cdot (\rho_{\alpha} \mathbf{q}_{\alpha}) = r_{\alpha}, \quad \alpha = c, w, \quad (3)$$

where ϕ [L³L⁻³] is porosity, S_{α} [-] is saturation of the α -phase, ρ_{α} [ML⁻³] is density of the α -phase, $\mathbf{q}_{\alpha}$ [L³L⁻²T⁻¹] is the volumetric flux of the α -phase, r_{α} [ML⁻³T⁻¹] is the phase change term (CO₂ dissolution into the aqueous phase will be considered, but not water evaporation into the CO₂) and α is either aqueous phase, w , or non-wetting phase, c . If the injected fluid is

the same as, or miscible with, that contained in the aquifer, only one phase would be considered.

The momentum conservation is expressed using Darcy's law, which reads

$$\mathbf{q}_\alpha = -\frac{kk_{r\alpha}}{\mu_\alpha}(\nabla p_\alpha + \rho_\alpha g \nabla z), \quad \alpha = c, w, \quad (4)$$

where k [L^2] is the intrinsic permeability of the aquifer, $k_{r\alpha}$ [-] is the α -phase relative permeability, μ_α [$ML^{-1}T^{-1}$] is the α -phase viscosity, p_α [$ML^{-1}T^{-2}$] is the α -phase pressure, g [LT^{-2}] is gravity and z [L] is the vertical coordinate.

Ferris et al. (1962) provides an analytical solution to this problem for one phase in a homogeneous aquifer, without a fault, with pumping through a trench that completely penetrates the aquifer. This geometrical setting is slightly different from the horizontal well configuration of Figure 4. But the difference in the injection boundary condition will affect the results only in the vicinity of the horizontal well because flow becomes horizontal (Dupuit approximation applies) at a distance from the injection well larger than 1.5 times the aquifer thickness (Batu, 1998). By changing the sign of the flow rate in the Ferris et al. (1962) solution, injection can be considered instead of pumping, resulting in a head change given by

$$s = \frac{Qx}{2T} \left[\frac{e^{-u^2}}{u\sqrt{\pi}} - 1 + \frac{2}{\sqrt{\pi}} \int_0^u e^{-v^2} dv \right] \text{ with } u = x \sqrt{\frac{S_a}{4Tt}}, \quad (5)$$

where s [L] is the head change, Q [$L^3T^{-1}L^{-1}$] is the injection rate per unit length, x [L] is the distance from the drain to the observation point, T [L^2T^{-1}] is the transmissivity of the aquifer and S_a [-] is the storage coefficient of the aquifer.

Equation (5) can be rewritten, by grouping the term in brackets that depends on the dimensionless variable u , as

$$s = \frac{Qx}{2T} D(u), \quad (6)$$

where $D(u) = \frac{e^{-u^2}}{u\sqrt{\pi}} - 1 + \frac{2}{\sqrt{\pi}} \int_0^u e^{-v^2} dv$. $D(u)$ does not have an analytical solution, but its last term is the error function, which has precise approximations. Figure 5 shows the values of $D(u)$ as a function of u .

Figure 5. Function $D(u)$ for values of u ranging from 10^{-4} to 2.3.

The head change can be calculated for a homogeneous aquifer using Equation (6). Pressure change can be easily calculated from head change as $\Delta p = \rho g s$. This analytical solution provides the scaling relationships of this application, which are useful to express the problem in its dimensionless form (see Section 2.4). However, the analytical solution is not valid for aquifers crossed by low-permeability faults or for compartmentalized aquifers, so numerical solutions are needed to predict the fluid pressure evolution of aquifers containing heterogeneities.

To estimate the distance from the fault to the observation well where the divergence has been identified, we first back-calculate at several observation wells the resulting value of u at which divergence in the derivative of overpressure occurs, i.e., $u = A$, where A is a non-

dimensional constant. Thus, the distance x_r from the injection well to the observation well, passing by the fault (see Figure 6), can be expressed from the definition of u as

$$x_r = A \sqrt{\frac{4Tt_{div}}{S_a}}. \quad (7)$$

Once the distance x_r is determined, the distance R from the observation well to the fault can be easily calculated as

$$R = \frac{x_r - x_{wells}}{2}, \quad (8)$$

where x_{wells} [L] is the distance between the injection well and the observation well as sketched in Figure 6.

Figure 6. Distance convention for fault location shown in a vertical cross section of the aquifer

To locate the fault, at least two observation wells are needed (one if pressure is also monitored at the injection well). With the two calculated R distances a simple triangulation gives the location of the fault. It should be kept in mind that the divergence time of the observation well that is located closer to the fault will be smaller. In this study, the fault strike is assumed known from independent data sources. In the more general case where the fault orientation is unknown, at least two observation wells contained in different sections perpendicular to the well would be needed.

2.4. Dimensionless form

To generalize the problem, we use dimensionless variables, with the following characteristic values:

- The characteristic distance x' is considered as the thickness of the aquifer.
- The characteristic transmissivity, T' , and characteristic storage coefficient, S'_a , are taken as those of the aquifer.
- The characteristic time has been defined as the time that satisfies $u = x' \sqrt{\frac{S'_a}{4T't'}} = 1$, which becomes $t' = \frac{S'_a x'^2}{4T'}$.
- The characteristic pressure p' is obtained from Equation (6), taking into account the relationship between pressure and head change, knowing that $D(u = 1) = 0.0503$ and equating the variables appearing in Equation (6) to their characteristic values, resulting in $p' = \frac{Qx'g\rho_w}{2T'} 0.0503$.

With these characteristic variables, the analytical solution of Ferris et al. (1962) becomes, in dimensionless form,

$$p_D = \frac{x_D}{0.0503} D\left(\frac{x_D}{\sqrt{t_D}}\right), \quad (9)$$

where the subscript D denotes a dimensionless variable and the function $D(u)$ depends solely on the dimensionless distance and dimensionless time. The distance x_r expressed in Equation (8), in dimensionless form, results in

$$x_{r_D} = A \sqrt{t_{div_D}}. \quad (10)$$

2.5. Numerical solution

We simulate a sufficiently extensive model, 40 km, so that the numerical solution is not affected by the nature of the outer boundary condition and thus the aquifer can be considered

as infinite (Figure 7). The no flow boundary conditions at the top and bottom boundaries represent low-permeability cap and base rock, respectively.

We consider four numerical configurations of the problem: two for water injection and two for CO₂ injection. For each fluid injection, we simulate injection both in a homogeneous aquifer and in an aquifer containing a low-permeability fault placed at 2.5 km from the injection well (fault F1 in Figure 7). Additionally, we consider a case with two faults to illustrate the applicability of the methodology to multiple faults. The injected water flow rate is $2.3 \cdot 10^{-5} \text{ m}^3/\text{s}/\text{m}$. For CO₂ injection, due to its high compressibility, CO₂ density increases as pressure builds up, so the volumetric flow rate tends to decrease with time. We have adjusted the CO₂ mass flow rate to obtain a volumetric flow rate similar to that of water injection, so both cases are comparable. The distances between the considered faults and the injection well are arbitrary, but within a value that may induce geomechanical issues due to excessive overpressure.

Figure 7. Schematic representation of the geometry and boundary conditions of the numerical 2D model, which may contain one or two low-permeability faults.

Table 1 includes the values of the parameters used in this study. The high-permeability rock used as an aquifer is representative of typical water-saturated sandstone or limestone and considered here to be at a depth of 1500m, with a temperature of 55°C. For the considered pressure and temperature of the aquifer, brine density is 1086.9 kg/m^3 , brine compressibility is $4.5 \cdot 10^{-10} \text{ Pa}^{-1}$ and viscosity is $5.2 \cdot 10^{-4} \text{ Pa}\cdot\text{s}$. The storage coefficient of the aquifer is

calculated assuming that only brine is present in the aquifer. The presence of CO₂, which is around three orders of magnitude more compressible than water, would yield a higher storage coefficient (see Vilarrasa et al., 2010 for a discussion on the effect of CO₂ compressibility on the storage coefficient). We consider the faults to have a permeability of 10⁻¹⁷ m². Nevertheless, the sensitivity of the overpressure response to the permeability of a fault is analyzed by varying fault permeability over six orders of magnitude. The influence of the nature of the injected fluid is analyzed as well, comparing water and CO₂ injection in a homogeneous aquifer.

Table 1 : Input parameters for the analytical and numerical analyses

Parameter		Model value	Dimensionless value
Characteristic distance [m]	x'	50	1
Aquifer intrinsic permeability [m ²]	$k_{aquifer}$	1.0·10 ⁻¹³	1
Characteristic transmissivity [m ² /s]	T'	1.026·10 ⁻⁴	1
Characteristic storage coefficient [-]	S'_a	2.399·10 ⁻⁵	1
Characteristic time [s]	t'	146.149	1
Characteristic pressure [MPa]	p'	3.003·10 ⁻³	1
Porosity of the aquifer [-]	ϕ	0.1	0.1
Intrinsic permeability of faults [m ²]	k_{fault}	10 ⁻¹⁵ -10 ⁻¹⁹	10 ⁻² -10 ⁻⁶
Thickness of faults [m]	b_{fault}	1	0.02

For the injection of each fluid, diagnostic plots are drawn at several points along the aquifer and the divergence time of the derivative of overpressures is determined for each point using Equation (2) with three possible thresholds equal to 0.3 m, 1.0 m and 3.0 m, which in

dimensionless form are 1.0, 3.3 and 10.0, respectively. These data points are used to find a relationship between the observed divergence time and the distance from the observation well to the fault in order to estimate the position of faults. To perform the numerical simulations, the finite element code CODE_BRIGHT (Olivella et al., 1994; 1996), extended for simulating CO₂ injection (Vilarrasa et al., 2010) is used.

3. RESULTS

3.1. Water Injection

3.1.1. *Homogeneous aquifer*

Figure 8 shows the diagnostic plot of water injection in a confined homogeneous aquifer when injecting through a large horizontal well. The diagnostic plot includes both the analytical solution of Ferris et al. (1962) and the numerical solution. The fitting between both solutions is very good, which suggests that for this problem geometry, the analytical solution of Ferris et al. (1962) can be used as a reference to compare with field measurements to determine whether a low-permeability fault is affecting fluid flow or not. Because of their simplicity, analytical solutions give almost immediate results, which is very helpful in case of simple geometries of the aquifer to assist decision makers in reacting fast to minimize the risk of inducing felt seismic events.

Figure 8. Diagnostic plot comparing the numerical and the analytical solution of Ferris et al. (1962) when injecting water in a homogeneous aquifer at an observation well placed at a dimensionless distance of 48 away from the injection well.

To obtain a smooth logarithmic derivative of the fluid pressure changes, it is crucial to perform pressure measurements at short intervals of time, on the order of seconds, at the beginning of injection. As the injection time increases, the measurements can progressively become less frequent. Otherwise, the logarithmic derivative may fluctuate and no tendency may be appreciable (see e.g., Renard et al., 2009).

3.1.2. Aquifer with a fault

Low-permeability faults act as a barrier to flow across them, thus causing an additional overpressure on the side of the fault that is closer to the injection well. However, this additional overpressure will only be noticeable if the permeability contrast between the fault and the aquifer is above a certain threshold. Figure 9 shows the diagnostic plot for the homogeneous case and for a permeability contrast between fault F1 and the aquifer that ranges from 2 to 6 orders of magnitude. For a fault permeability that is 2 orders of magnitude

lower than that of the aquifer, both the overpressure and its derivative are indistinguishable from those of the homogeneous case. Some slight changes can be observed when the permeability contrast is of 3 orders of magnitude. However, the additional overpressure is very small and it may not be necessary to adopt mitigation measures to reduce overpressure. For larger permeability contrasts, overpressure increases moderately with respect to the homogeneous case. Nevertheless, for permeability contrasts larger than 4 orders of magnitude, the resulting overpressure remains similar to the overpressure induced by a permeability contrast of 4 orders of magnitude.

Figure 9: Diagnostic plot showing a sensitivity analysis of the permeability of fault F1 on overpressure response. k_{FD} is the dimensionless permeability of the fault. The overpressure is measured at a dimensionless distance from the injection well of 2 towards the fault. The effect of a low-permeability fault starts to be observable if the permeability of the fault is at least 3 orders of magnitude lower than that of the aquifer.

As for the divergence time, it is the same in all cases. Thus, a low-permeability fault can be accurately located regardless of its permeability if the permeability contrast is enough to create a deviation from the case without the fault, i.e., higher than 3 orders of magnitude. In

what follows, we use in our numerical simulations a fault permeability that is 4 orders of magnitude lower than that of the aquifer, which is the minimum permeability contrast that yields an additional pressure buildup that might jeopardize fault stability.

Figure 10 displays the derivative of overpressure of a homogeneous aquifer and an aquifer that contains the low-permeability fault F1 for two observation wells placed symmetrically with respect to the injection well. We plot only the derivative of overpressure because it is the curve that we use to determine the divergence time. Divergence between the homogeneous aquifer and the aquifer with a fault occurs earlier at the observation well that is placed closer to the fault. Since the additional overpressure caused by the low-permeability fault is reflected from the fault, the observation well that is closer to the fault feels the effect of the fault earlier. Nevertheless, after a transition period, the derivatives of the two observation wells tend to converge to the same curve, which is a typical feature of aquifers containing some kind of heterogeneity (e.g. Butler, 1988; Vilarrasa et al., 2011).

Figure 10: Dimensionless derivative of overpressure in a homogeneous aquifer and in an aquifer with the low-permeability fault F1 at two symmetric observation wells placed at a dimensionless distance of 40 away from the injection well.

Once the divergence time is determined at an observation well, since we know the distance travelled by the pressure perturbation front up to the fault and back to the observation well, we can back-calculate the value of A either from Equations (7) or (10) in dimensional or dimensionless form, respectively. Table 2 includes the actual dimensionless x_r value (recall Figure 6), the dimensionless divergence time, and the A -value at several observation wells for the three considered thresholds for the difference between the pressure derivative of the cases with and without fault. The smaller the threshold, the smaller the divergence time and thus, the higher the A -value (recall Equation (10)). Furthermore, the calculated A -value decreases as the observation well is placed closer to the fault. This implies that the pressure derivative when a fault is present diverges from the derivative when there is no fault with less anticipation as the observation well gets closer to the fault, but the fault can be detected earlier.

Table 2: A-values for water injection at 15 observation wells. The variables are expressed by dimensionless values

x_{wells_D}		Threshold=1.0		Threshold=3.3		Threshold=10.0	
(positive towards fault F1)	x_{r_D}	t_{div_D}	A-value	t_{div_D}	A-value	t_{div_D}	A-value
-180	280	11931	2.563	14318	2.340	18489	2.059
-160	260	9000	2.548	12598	2.316	16124	2.048
-140	240	7771	2.530	11057	2.282	13987	2.029
-120	220	6677	2.496	9302	2.281	12000	2.008
-100	200	10410	2.448	7884	2.252	10185	1.982
-80	180	5530	2.421	6657	2.206	8544	1.947
-60	160	4419	2.407	5354	2.187	6894	1.927
-40	140	3529	2.357	4278	2.140	5427	1.900

-20	120	2676	2.320	3204	2.120	4117	1.870
-10	110	2210	2.340	2820	2.071	3543	1.848
-2	102	1915	2.331	2400	2.082	3134	1.822
2	98	1796	2.312	2208	2.086	2921	1.813
10	90	1492	2.330	1931	2.048	2549	1.783
20	80	1250	2.263	1576	2.015	2070	1.758
40	60	718	2.239	982	1.915	1294	1.668

To estimate the position of a low-permeability fault, two observation wells are required because from the divergence time, we can know the distance to the fault, but not on what side of the observation well the fault is placed. For example, if we take an observation well that has the same x_r with respect to the faults F1 and F2 (recall Figure 7), i.e., an observation well placed at $x_D = -50$, the overpressure evolution, and thus its derivative, are identical when either F1 or F2 are active. Therefore, just by observing at one observation well, the position of the fault cannot be determined and a second observation well is necessary to locate the fault.

Figure 11 plots the relationship given by Equation (10) between the dimensionless divergence time and the dimensionless distance from the observation well to the fault. The A -value equals 2.25 in Figure 11, which also includes the data pairs of measured divergence time and actual distance to the fault for the intermediate threshold, i.e., 3.3. Additionally, we have fitted the data pairs to a power law (see Figure 11), obtaining a power slightly higher than 0.5. Figure 11 can be used to quickly estimate the position of the first detected low-permeability fault. To detect more faults, the detected low-permeability fault should be incorporated in the numerical model to predict the future pressure evolution including this fault and repeat the process indicated in Figure 3.

Figure 11. Dimensionless distance travelled by the pressure perturbation front as a function of the dimensionless divergence time for a A -value equal to 2.25. The measurements made using the numerical models in the observation wells included in Table 2 are also shown, together with the power law that best fits these numerical measurements.

3.1.3. Multiple faults

Figure 12 illustrates how a second fault can be detected and located. The two observation wells that are used are placed at a dimensionless distance of 40 at each side of the injection well. Initially, the derivative of the measured overpressure is compared against the derivative of the overpressure that would correspond to a homogeneous aquifer. The first divergence ($t_{div_{D1}}$), assuming a threshold of 3.3, is measured at the well placed to the right of the injection well at a dimensionless time of 982 (Figure 12b). Using Equation (10) with a A -value of 2.25, gives a dimensionless distance from the injection well to the fault and back to the observation well (recall Figure 6) of 70, but if the regression indicated in Figure 11 is used, the dimensionless distance is of 61, which is closer to the actual distance, i.e., 60. Since the two observation wells are placed at the same distance from the injection well, we know that the low-permeability fault is located on the side of the observation well that detects the

divergence in the overpressure derivative first. At this moment, there is some uncertainty in the location of the fault, but we can incorporate the fault in the numerical model and compare the derivative of the overpressure measurements at this well with the pressure derivative predicted by the model that includes the detected low-permeability fault.

Figure 12. Dimensionless derivative of overpressure at two observation wells showing the procedure to detect more than one fault. The observation wells are located at a dimensionless distance of 40, (a) to the left and (b) to the right, away from the injection well. The first divergence time, $t_{div_{D1}}$, is used to locate the fault that is closer to the injection well (fault F1). To detect the second fault, the derivative of the measured overpressure is compared against the

derivate of the overpressure predicted numerically including fault F1. The location of the second fault (fault F2) is estimated from the divergence time $t_{div_{D_2}}$.

The effect of the detected low-permeability fault is noted at the other observation well, i.e., the one placed at the dimensionless x -coordinate of -40, at a dimensionless time of 4278 (Figure 12a). This value can be used to reduce the uncertainty on the location of the already detected fault. The dimensionless distance from the injection well to the fault and back to the observation well is of 147 and 142 if it is calculated using Equation (10) or the regression shown in Figure 11, respectively. The actual distance is of 140, so the fault is slightly closer to the injection well than the distance predicted using the proposed methodology. Nevertheless, for detecting and locating fault F2, we use the location of F1 shown in Figure 7.

Now, the derivative of the measured overpressure is compared against the overpressure derivative of a model including fault F1. The evolution at the observation well placed at -40 diverges again ($t_{div_{D_2}}$) at a dimensionless time of 5338 (Figure 12a). This corresponds to a dimensionless distance to the second fault of 164 and 161 when using Equation (10) or the regression shown in Figure 11, respectively. The actual distance is 160, so the prediction again slightly overestimates the distance from the fault to the injection well. Similarly as for the first fault, the second fault is located on the side of the injection well where it is first located. The divergence time at the other observation well occurs at a dimensionless time of 11239 (Figure 12b), which corresponds to a dimensionless distance of 239 and 246 if it is calculated using Equation (10) or the regression shown in Figure 11, respectively. Again, the estimated distance to the fault is very similar to the actual distance, which is of 240. This process would be repeated to detect and locate more low-permeability faults that could intersect the aquifer.

3.2. CO₂ Injection

3.2.1. Homogeneous aquifer

Figure 13 shows the diagnostic plot for water and CO₂ injection in a homogeneous aquifer. The overpressure evolution is very similar for both fluids. However, overpressure induced by CO₂ injection is slightly lower than that of water injection because of the CO₂ compressibility and CO₂ dissolution. When CO₂ dissolves into the brine, the resulting volume becomes smaller than the addition of the volumes of the two phases separately before dissolution takes place. This volume decrease causes a reduction in overpressure. Furthermore, as pressure builds up, CO₂ density increases and thus, a smaller amount of brine is displaced, which induces a smaller overpressure (Vilarrasa et al., 2010).

Figure 13: Diagnostic plot for water and CO₂ injection in a homogeneous aquifer at an observation well placed at a dimensionless distance equal to 40.

The derivative resulting from CO₂ injection follows a similar trend as that for water injection. This similarity suggests that the solution of Ferris et al. (1962) could be used as a first approximation for CO₂ injection in a homogeneous aquifer. The most critical aspect is probably making a good estimation of the CO₂ density because overpressure controls CO₂

density and CO₂ density affects overpressure. To determine the CO₂ density that corresponds to the induced overpressure, the methodology proposed by Vilarrasa et al. (2010) could be used. However, it is recommendable to use numerical models that simulate CO₂ injection.

3.2.2. *Aquifer with a fault*

Figure 14 displays the CO₂ plume when injection takes place in an aquifer containing fault F1. The additional overpressure induced by the fault causes an asymmetric evolution of the CO₂ plume. Since overpressure is higher on the side of the fault, CO₂ advance finds more resistance there and thus, CO₂ preferentially flows away from the fault. Therefore, CO₂ breakthrough at observation wells placed at the same distance from the injection well, but in opposite directions, can give information on the possible presence of faults that could be affecting fluid flow.

Figure 14: CO₂ plume after a dimensionless time of $5.9 \cdot 10^4$ (100 days). The presence of a low-permeability fault causes an asymmetric growth of the CO₂ plume due to the higher overpressure on the side of the fault.

Figure 15 shows the overpressure derivative at two observation wells placed symmetrically with respect to the injection well for a homogeneous aquifer and an aquifer containing fault F1. The closer the observation well is to the fault, the earlier the pressure derivative diverges from that of the aquifer without the fault. The pressure derivative evolution is very similar to that resulting from the injection of water (Figure 10). Unlike water, CO₂ is buoyant and therefore, fluid flow is not homogeneous around the CO₂ plume.

Actually, since most of the CO_2 advances through the top of the aquifer, overpressure becomes slightly higher at the top than at the bottom of the aquifer. For example, the overpressure difference between the top and the middle of the aquifer after a dimensionless time of $5.9 \cdot 10^4$ (100 days) at a dimensionless distance of 1 from the injection well is of a dimensionless pressure of 13 (0.04 MPa). Though overpressure differences at different depths are small, they can be valuable to obtain information on the aquifer heterogeneity and CO_2 plume evolution (Strandli and Benson, 2013). However, these differences in overpressure with depth vanish with distance to the well and become negligible at a distance of a few aquifer thicknesses. Furthermore, this overpressure dependence with depth does not affect the divergence time, so the depth of the fluid pressure measurements is not important for the purposes of the proposed methodology to detect faults for reducing the risk of inducing seismicity.

Figure 15. Dimensionless derivative of overpressure induced by CO_2 injection in a homogeneous aquifer and in an aquifer containing the low-permeability fault F1. The derivative is plotted at two observation wells that are symmetric with respect to the injection well and are located at a dimensionless distance of 40 away from it.

As in the case of water injection, we measure the divergence time at several observation wells to determine the A -value that best predicts the position of the fault. Table 3 contains the same information as Table 2, but for CO_2 injection. A similar A -value, but slightly lower than for water injection is obtained. This lower value implies that for a given distance, the divergence time occurs later when CO_2 is injected. This delay in divergence is due to the higher compressibility of CO_2 with respect to water, which causes an increase in the storage coefficient inside the CO_2 plume and thus yields a retardation of the overpressure propagation. The position of a low-permeability fault, using a dimensionless threshold of 3.3, can be estimated with either Equation (10) using a A -value of 2.15, or with the power law indicated in Figure 16, which is similar to that for water injection (recall Figure 11).

Figure 16. Dimensionless distance travelled by the pressure perturbation front when injecting CO_2 as a function of the dimensionless divergence time for a A -value equal to 2.15. The measurements made using the numerical models in the observation wells included in Table 3 are also shown, together with the power law that best fits these numerical measurements.

Table 3: A-values for CO₂ injection at 15 observation wells. The variables are expressed by dimensionless values

x_{wells_D}		<i>Threshold=1.0</i>		<i>Threshold=3.3</i>		<i>Threshold=10.0</i>	
<i>(positive towards fault F1)</i>	x_{r_D}	t_{div_D}	<i>A-value</i>	t_{div_D}	<i>A-value</i>	t_{div_D}	<i>A-value</i>
-180	280	12179	2.537	15170	2.273	19252	2.018
-160	260	10745	2.508	13450	2.242	17141	1.986
-140	240	9663	2.441	11614	2.227	14577	1.988
-120	220	8023	2.456	9845	2.217	12497	1.968
-100	200	6856	2.415	8459	2.175	10807	1.924
-80	180	5759	2.372	7159	2.127	9060	1.891
-60	160	4688	2.337	5852	2.092	7256	1.878
-40	140	3748	2.287	4578	2.069	5676	1.858
-20	120	2803	2.266	3370	2.067	4327	1.824
-10	110	2346	2.271	2953	2.024	3719	1.804
-2	102	2046	2.255	2540	2.024	3271	1.783
2	98	1884	2.258	2423	1.991	3031	1.780
10	90	1614	2.240	2075	1.976	2619	1.759
20	80	1297	2.221	1656	1.966	2102	1.745
40	60	792	2.132	984	1.912	1285	1.674

4. DISCUSSION

We propose a methodology to reduce the risk of inducing felt seismic events that uses diagnostic plots to detect and locate low-permeability faults. The concept consists in identifying divergence of the logarithmic derivative of overpressure measurements compared to the expected logarithmic derivative of overpressure evolution in an aquifer that includes the

previously identified heterogeneities. If a fault is detected and located, it should be incorporated into the model to compare the future pressure measurements against the updated model. Furthermore, if the flow rate varies with time, the variability should be included in the model. The use of diagnostic plots is very helpful in determining the divergence of the pressure derivatives because the logarithmic derivative is very sensitive to slight variations in the overpressure evolution (Renard et al., 2009) and permits detecting low-permeability faults with significant anticipation compared to the divergence time in the overpressure evolution. The shape of both overpressure and overpressure derivative should be analyzed to ensure that the divergence effectively corresponds to a low-permeability fault and not to another feature (see, e.g., Renard et al., 2009).

The proposed fault detection methodology to minimize the risk of inducing seismicity has a wide range of applications, including wastewater disposal, geothermal energy, seasonal natural gas storage, underground compressed air energy storage, and geologic carbon storage. Though analytical solutions to estimate overpressure evolution in a homogeneous aquifers are more developed for water injection than for gas injection, several analytical solutions for two-phase flow have been developed recently (e.g., Nordbotten et al., 2005; Dentz and Tartakovsky, 2009; Mathias et al., 2011; Houseworth, 2012; Vilarrasa et al., 2013a). These analytical solutions for infinite aquifers, and other solutions incorporating heterogeneities such as faults (Zeidouni, 2012; Kang et al., 2014) and compartmentalized aquifers (Zhou et al., 2008), may be incorporated in numerical solutions to speed up the calculations (Celia and Nordbotten, 2009). The performance of these solutions usually depends on the gravity number (gravity to viscous forces) (Vilarrasa et al., 2010), so this number should be evaluated to decide which solution is more appropriate in each case.

To illustrate the applicability of the proposed methodology, we have considered an infinite horizontal aquifer in which fluid is injected through a horizontal well and one or two low-

permeability faults may be present parallel to the well. Horizontal wells are common, especially in aquifers with not very high permeability and/or in thin aquifers, as at In Salah, Algeria (Rinaldi et al., 2014). Our model is a 2D cross section perpendicular to the well, so the pseudo-radial flow that develops in the long-term (Al Rbeawi and Tiab, 2013; Sheng, 2014) cannot be modeled. Despite this limitation, simulation results show that the proposed methodology can be successfully applied to detect and locate low-permeability faults both for water and CO₂ injection. We found that fault permeability should be at least three orders of magnitude lower than that of the aquifer in order to detect a fault from pressure derivative changes. It should be noted that higher fault offset may be accompanied by larger decrease in the cross-fault permeability, which enhances fault detectability using the pressure analysis presented in this study. Also, higher offset makes it easier for the fault to be detected using seismic data. For water injection, we have illustrated how a second fault can be detected and located (recall Figure 12). Though the estimation of the fault location has some uncertainty, the proposed methodology gives a good estimate of the position of faults. Thus, despite the apparent simplicity of the methodology to detect and locate low-permeability faults, this application example that detects and locates two faults highlights the potential to apply the methodology to other geological settings and geometrical configurations.

We have assumed in our application that both the caprock and baserock are impermeable. However, these low-permeability formations may have a non-negligible permeability at the field scale due to the presence of fractures that may enhance matrix permeability up to three orders of magnitude (Neuzil, 1986). Thus, overpressure will be released in the aquifer, which is beneficial for the geomechanical stability of faults (Vilarrasa and Carrera, 2015). Overpressure may also be reduced due to hydromechanical couplings through which fractures are opened up due to a decrease of the normal effective stress acting on the fault plane, thus increasing permeability (Rutqvist, 2015). Permeability may also be enhanced if shear slip

occurs because of the increase in the fracture aperture caused by the dislocation of the fracture planes (Rutqvist and Stephansson, 2003). A combination of both mechanisms occurred at In Salah, Algeria, as a result of CO₂ injection (Vilarrasa et al., 2015), which enhanced the permeability of the fractured aquifer by a factor of 3 (Rinaldi et al., 2014). We have tested the effect of the hydromechanical couplings considering the Kozeny-Carman relationship between permeability and porosity, which works well for sandstones (Doyen, 1988). Nevertheless, for the range of overpressures induced in our simulations, i.e., several MPa, the effect of deformation on pressure evolution was negligible, so we deemed not necessary to include it in all the simulations.

Once a fault is detected, mitigation measures should be carried out to avoid excessive overpressure that could jeopardize fault stability (e.g., Hsieh and Bredehoeft, 1981; Cappa and Rutqvist, 2011b; Jha and Juanes, 2014; Rinaldi et al., 2015). To assess the likelihood of a fault undergoing shear failure and thus, inducing a seismic event, stress state measurements and a proper hydromechanical characterization are key (Juanes et al., 2012; Vilarrasa et al., 2013b). The proposed methodology will allow to determine the orientation of the fault with small uncertainty, but the dip and strength of the fault should be estimated from other characterization and monitoring techniques, such as 3D seismics, electric tomography and microseismicity monitoring.

Thermo-mechanical couplings should also be considered because induced thermal stresses may compromise fracture stability around the injection well, where a cold region may form (de Simone et al., 2013), and even modify the stability of certain faults in the far-field (Jeanne et al., 2014). If it is envisaged from fault stability analysis (considering the uncertainties in the fault properties and characteristics) that any fault is approaching failure conditions, overpressure should be reduced at the injection well to avoid fault reactivation.

An effective way of improving pressure management would be to combine pressure measurements, thermo-hydro-mechanical numerical modeling and microseismicity monitoring and interpretation. This integration is starting to be performed in stimulation of low-permeability rocks in enhanced geothermal systems (Tarrahi et al., 2015). Since microseismicity is usually abundant when fluids are injected deep underground (e.g., Phillips et al., 2002; Shapiro et al., 2003; Evans et al., 2012; Stork et al., 2015), the magnitude of the induced seismicity was proposed as an indicator to assist decision making on how to proceed with fluid injection. This criterion is known as the traffic light system (see, e.g., Bachmann et al., 2011) and works as follows. If the magnitude of the induced earthquakes remains below a certain level, injection continues as planned. But if seismicity surpasses that threshold, injection is reduced, and even stopped if seismicity reaches unacceptable levels. However, this method has proven to be unsuccessful, i.e., unable to anticipate felt induced seismicity, at several sites (Majer et al., 2007). Thus, hydraulic methods, such as the one proposed in this study, which allow determining whether a fault is being affected by overpressure with sufficient anticipation, will provide additional information to the operators of injection sites to decide on how to perform an efficient pressure management that minimizes the risk of inducing felt seismic events.

5. CONCLUSIONS

We propose a methodology to detect and locate low-permeability faults, so that the risk of inducing felt seismic events can be reduced. To compute the divergence time between the logarithmic derivative of the measured overpressure and that corresponding to an aquifer including the previously identified heterogeneities, we use diagnostic plots because the logarithmic derivative of the overpressure is very sensitive to slight variations in its trend. Thus, the hydraulic signature of a low-permeability fault can be identified much earlier than

by observing just the overpressure evolution. Once a fault is located, the fault should be incorporated in the numerical model to enable detection of other faults by comparing the pressure derivative of the measured overpressure against the pressure derivative predicted by the updated model. We apply the methodology to a confined aquifer that may contain one or two faults parallel to a horizontal injection well through which we inject water or CO₂. We show that the method can be applied successfully and low-permeability faults can be detected and located with time enough to perform mitigation measures to reduce excessive overpressure that could compromise fault stability. Simulation results illustrate that faults affect overpressure evolution if the permeability contrast between the aquifer and the fault is at least of three orders of magnitude. This methodology to detect and locate low-permeability faults to reduce the risk of inducing seismicity is applicable to most injection sites, including applications like wastewater disposal, geothermal energy, seasonal natural gas storage, underground compressed air energy storage, and geologic carbon storage.

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