



HAL
open science

CO₂ plume and pressure monitoring through pressure sensors above the caprock

Xiaojin Zheng, D. Nicolas Espinoza, Matthieu Vandamme, Jean-Michel Pereira

► **To cite this version:**

Xiaojin Zheng, D. Nicolas Espinoza, Matthieu Vandamme, Jean-Michel Pereira. CO₂ plume and pressure monitoring through pressure sensors above the caprock. *International Journal of Greenhouse Gas Control*, 2022, 117, 39 p. 10.1016/j.ijggc.2022.103660 . hal-03905395

HAL Id: hal-03905395

<https://enpc.hal.science/hal-03905395v1>

Submitted on 18 Dec 2022

HAL is a multi-disciplinary open access archive for the deposit and dissemination of scientific research documents, whether they are published or not. The documents may come from teaching and research institutions in France or abroad, or from public or private research centers.

L'archive ouverte pluridisciplinaire **HAL**, est destinée au dépôt et à la diffusion de documents scientifiques de niveau recherche, publiés ou non, émanant des établissements d'enseignement et de recherche français ou étrangers, des laboratoires publics ou privés.



Distributed under a Creative Commons Attribution 4.0 International License

1 **CO₂ Plume and Pressure Monitoring through Pressure Sensors above the** 2 **Caprock**

3 Xiaojin Zheng, D. Nicolas Espinoza

4 *Hildebrand Department of Petroleum and Geosystems Engineering, The University of Texas at Austin,*
5 *Texas, USA*

6 Matthieu Vandamme, Jean-Michel Pereira

7 *Navier, École des Ponts, Université Gustave Eiffel, CNRS, Marne-la-Vallée, France*

8 **Abstract**

9 Commercial-scale development of CO₂ geological storage necessitates robust and real-time
10 monitoring methods to track the injected CO₂ plume and provide assurance of CO₂ storage. Pressure
11 monitoring above the injection zone is a method to detect potential CO₂ leaks into overlying
12 formations. We present a generic CO₂ storage model with a single injector to predict pressure
13 changes above the caprock due to both fast hydraulic communication and partially undrained loading,
14 the latter often neglected in reservoir simulation. The simulation used a compositional simulator
15 coupled with geomechanics to solve the poroelastic equations in the entire storage complex. The
16 results show that changes of pore pressure above the caprock caused by partially undrained loading
17 reach up to ~15 kPa within ~10 days followed by a gradual decay with time. This is about 1% of the
18 pressure increase in the injection zone. Furthermore, the pressure changes above the caprock are
19 closely related to the advance of the CO₂ plume. The results also include forward simulations
20 considering the presence of: a fault either with high or low permeability, a poorly isolated abandoned
21 well, a leaky injector, and a second injector. Fluid flow through high permeability paths across the
22 caprock favors a ~one order of magnitude higher, yet more gradual pressure increase than the base
23 case with a fully covering caprock. Pressure monitoring above the caprock is a feasible technology to

24 track the CO₂ plume, requires high precision pressure measurements, and must account for partially
25 undrained poroelastic loading to interpret correctly measured pressure signals in the field.

26 **Keywords:** poroelasticity, CCUS, wellbore instrumentation, leaks, caprock integrity

27 1. Introduction

28 The successful development of carbon dioxide (CO₂) geological storage necessitates robust and real-
29 time monitoring methods to detect potential CO₂ leakage into overlying formations and provide
30 assurance for permanent CO₂ trapping (Kim & Hosseini, 2015; Meckel et al., 2008). Most monitoring
31 techniques are based on measurements on the surface and in the injection zone. On-surface
32 monitoring (such as 4D seismic and InSAR mapping) can capture large geophysical features but is
33 limited by high costs, laborious interpretation, difficulty to capture low CO₂ saturations, and a large
34 attenuation of signals imposed by the overburden (Arts et al., 2004; Rutqvist et al., 2010). Monitoring
35 in the injection zone (IZ) involves fluid sampling, rock analysis, and placement of sensors in the target
36 formation, enables direct access to the zone of interest, and offers direct evidence for leak detection,
37 but remains limited to a few observation wells and small sampling volumes (Ajo-Franklin et al., 2013;
38 Hovorka et al., 2006; Zeidouni & Pooladi-Darvish, 2012b, 2012a).

39 Pressure monitoring above the injection zone (AIZ) is an alternative approach to monitor CO₂
40 injection and detect undesirable migration of fluids from the injection zone to overlying formations
41 (Liebscher et al., 2013; Park et al., 2012; Wiese et al., 2013; Zhang et al., 2019). AIZ pressure
42 monitoring can be done above the injection point but in the same storage formation, e.g. Decatur and
43 Otway field cases (Bauer et al., 2016; Ennis-King et al., 2017), or above the caprock, e.g. Cranfield and
44 Ketzin field cases (S. Hosseini et al., 2018; Wiese et al., 2013). AIZ pressure monitoring is relatively
45 inexpensive, covers a wider area than the IZ monitoring, and has the potential to detect leaks into
46 overlying formations if monitored above the caprock (S. Hosseini et al., 2018). This type of
47 monitoring takes advantage of the pressure changes caused by injection with a pressure front moving

48 faster than the injected fluid (Rutqvist 2012). Significant work has been done to predict and identify
49 leakages through abandoned wellbores due to direct hydraulic communication between the IZ and
50 the AIZ through analytical models and numerical simulation (Cihan et al., 2013; González-Nicolás et
51 al., 2015; Jung et al., 2013; Namhata et al., 2016; Sun & Durlofsky, 2019; Zhang et al., 2018).

52 Pore pressure increases above the caprock were thought to be zero in the absence of high
53 permeability paths across the caprock or adjacent faults with high permeability. Thus, any deviation
54 from the pressure baseline (expected to be constant) was considered as a result of high hydraulic
55 communication that could become a potential leak if the high permeability path is reached by the CO₂
56 plume. However, recent pressure monitoring in the Cranfield CO₂ injection project indicates
57 measurable changes of pore pressure above the caprock (~50 kPa) after two years of CO₂ injection
58 with IZ pressure change reaching a maximum of ~8.8 MPa in the absence of leaks (Kim & Hosseini,
59 2014; Tao et al., 2012). Analytical and numerical simulation work demonstrates that rock
60 deformation above the injection zone can induce pressure changes in the absence of leaks through
61 the caprock, by means of a poroelastic phenomenon known as “undrained loading” (Kim & Hosseini,
62 2014; Zeidouni & Vilarrasa, 2016). Despite recent advances and numerical simulations, pressure
63 monitoring above the caprock remains largely underutilized or misinterpreted because of a lack of
64 (1) validation schemes, (2) discrimination between fast hydraulic communication and undrained
65 loading, (3) thorough measurement of poromechanical properties of the AIZ, (4) thorough
66 deployment of high-resolution sensors to capture subtle pressure changes (e.g., 1 kPa), (5) coupled
67 poroelastic simulation beyond the injection zone for all CO₂ storage projects, (6) extension of existing
68 models to two-phase fluid flow, (7) accurate prediction of absolute magnitude and transient pressure
69 changes in the AIZ, and (8) evaluation of other leaking/sealing scenarios beyond just one leaky
70 abandoned well (S. Hosseini et al., 2018; S. A. Hosseini, 2019; S. Hosseini & Alfi, 2016; Kim & Hosseini,
71 2014; Mishra et al., 2014; Wiese et al., 2013; Zeidouni & Vilarrasa, 2016).

72 CO₂ injection and reservoir pressurization cause displacements and deformations far beyond the
73 extent of the CO₂ plume (Rutqvist et al., 2010; Segall & Fitzgerald, 1998; Tang et al., 2021). Fluid
74 injection and reservoir pressurization may result in ground surface uplift due to expansion of the
75 reservoir caused by decreased effective stress. For example, InSAR data showed a surface uplift on
76 the order of 5 mm per year in the In Salah Gas Project in Algeria (with a CO₂ injection rate of 0.5–1
77 Mt/year) (Rutqvist et al., 2009, 2010). CO₂ injection and reservoir pressurization also causes rock
78 deformation between the surface and the reservoir which may appear as a change of pore pressure
79 in fluid-saturated rocks (Detournay & Cheng, 1988; Roussel & Agrawal, 2017; Segall & Fitzgerald,
80 1998; Zeidouni & Vilarrasa, 2016). During a drained process, the application of an external stress
81 induces volumetric strains without change of pore pressure. In contrast, pore pressure will increase
82 in an undrained process when a (contraction) volumetric deformation is applied to a fluid-filled
83 porous material (Cheng, 2016; Coussy, 2004). Hence, even in the absence of fast hydraulic
84 communication between the injection zone and formations above the caprock, CO₂ (or any fluid)
85 injection can modify the pore pressure above the caprock due to undrained loading.

86 In general, two mechanisms can contribute to pore pressure changes in porous media (1) advective
87 fluid transport and (2) pore volume deformation. These coupled pore pressure diffusion and
88 mechanical deformation processes are captured by the pressure P diffusivity equation for fluid flow
89 coupled with poroelasticity with respect to time t (Cheng, 2016; Coussy, 2004; Detournay & Cheng,
90 1993):

$$91 \quad \frac{\partial P}{\partial t} = \frac{kM^*}{\mu} \nabla^2 P - \alpha M^* \frac{\partial \varepsilon_V}{\partial t} \quad (1)$$

92 where k is the porous medium permeability, μ is the fluid viscosity, α is the Biot coefficient, ε_V is the
93 bulk volumetric strain, and the Biot modulus M^* is

$$94 \quad M^* = \left(\frac{\phi_0}{K_f} + \frac{\alpha - \phi_0}{K_m} \right)^{-1} \quad (2)$$

95 where ϕ_0 is the initial rock porosity, K_f is the bulk modulus of the pore fluid, and K_m is the bulk
 96 modulus of the rock matrix. Notice that Eq. 1 is the pressure diffusivity equation with total
 97 compressibility ($C_t = 1/M^*$), where the second term in the right-hand side captures the impact of
 98 rock deformation on pressure changes. Reservoir simulation without geomechanical coupling (or
 99 just one-way coupling) captures the first term on the right-hand side of Eq. 1 only.

100 For a linear elastic isotropic porous solid, the expected pore pressure change ΔP under undrained
 101 loading (no change in fluid mass within pore volume) is directly proportional to the imposed
 102 volumetric strain (Coussy, 2004):

$$103 \quad \Delta P = -\alpha M^* \Delta \varepsilon_V \quad (3)$$

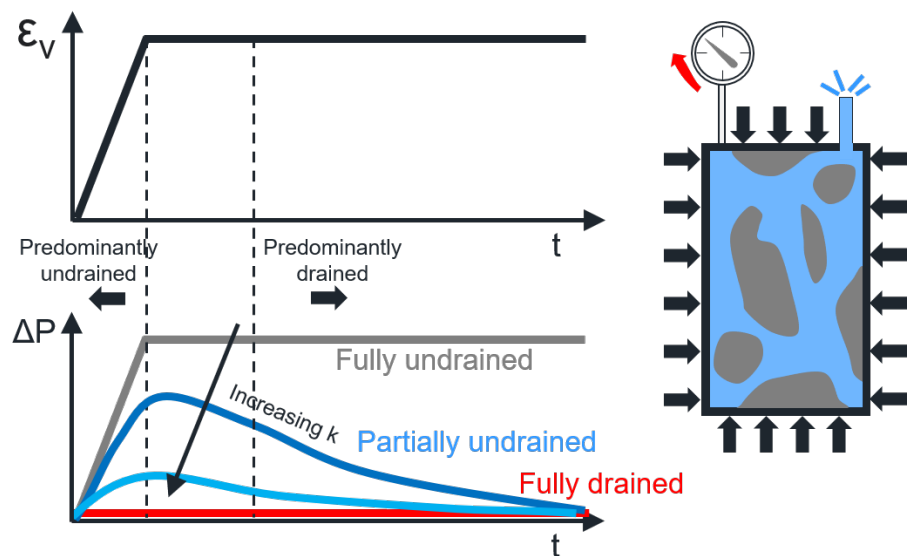
104 Thus, pore pressure change due to undrained loading depends on rock poroelastic properties, fluid
 105 compressibility (K_f)⁻¹, and volumetric strain. Decreases in pore volume lead to increases of pore
 106 pressure, while increases in pore volume lead to decreases of pore pressure for fully or partially
 107 undrained loading (Fig. 1).

108 Whether a process is undrained or drained depends on the rate of (strain) loading and the rate of
 109 pore pressure diffusion. Perfect fluid containment is rare in natural environments, so most processes
 110 can be generalized as partially undrained depending on the time interval of analysis. For example,
 111 the characteristic time of pressure diffusion T_{ch} captures the time when $\sim 2/3$ of the pore pressure is
 112 dissipated from an initial undrained loading state (Cheng, 2016):

$$113 \quad T_{ch} = \frac{L^2}{D_h} \quad (4)$$

114 where L is the characteristic drainage length and $D_h = \frac{kM^*}{\mu}$ is the hydraulic diffusivity. Higher
 115 permeability and shorter characteristic distance of drainage decrease the characteristic pore
 116 pressure diffusion time and the magnitude of pore pressure increase for partially undrained loading
 117 of real sediments (Fig. 1). Thus, the partially undrained condition entails a smaller amount of pore

118 pressure variations than the fully undrained condition due to pressure dissipation. In fact, if the rate
 119 of (strain) loading is lower than the rate of pore pressure diffusion, a porous medium may never
 120 experience a pore pressure change due to pore volume reduction. Additional constitutive equations
 121 for the multiphase fluid flow, the poroelastic solid, and coupled hydro-mechanical simulation are
 122 available elsewhere (Cheng, 2016; Coussy, 2004; Prevost, 2013; Tran et al., 2009).



123
 124 **Fig. 1.** Comparison among fully drained, partially undrained, and undrained conditions: the pore pressure
 125 changes under the partially undrained condition are proportional to the imposed volumetric strain but also
 126 depend on the hydraulic diffusivity of the porous medium.

127 The objective of this paper is to extend the current knowledge on pore-pressure monitoring above
 128 the caprock, mostly limited to leakages due to hydraulic communication, and make evident the
 129 impact of deformation-induced partially undrained loading. Such improvement is critical to establish
 130 pore-pressure monitoring above the caprock as a new subsurface signal that can potentially track
 131 the CO₂ plume, quantify hydraulic communication, detect possible leaks, and help ensure safe CO₂
 132 storage. The paper starts with a description of the compositional fluid flow model coupled with
 133 geomechanics. We put special emphasis on examining the poroelastic response above the caprock by

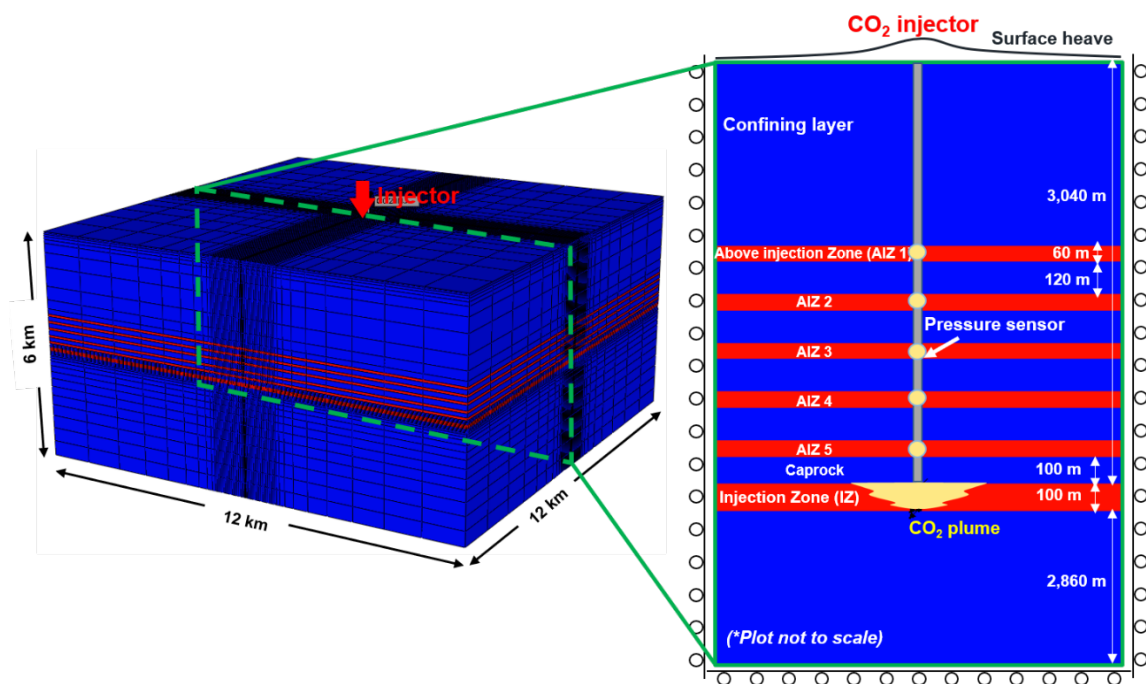
134 analyzing the magnitude, evolution, and distribution of the pressure increase through forward
135 modeling. The modeling work excludes pressure monitoring above the injection point but within the
136 same storage formation, since such response is expected to be dominated by fluid advection. The
137 analysis also discusses the possible configuration of pressure sensors regarding their position with
138 respect to the injector, horizontally and vertically above the caprock. The discussion section
139 considers the presence of various subsurface scenarios relevant to inverse analysis, including the
140 presence of a poorly isolated injector wellbore, a leaky abandoned wellbore, a high-
141 permeability/sealing fault, and two injectors.

142 2. Methodology

143 We use a fluid-flow compositional model coupled with poroelasticity for the entire storage complex,
144 including overburden and underburden layers, which are usually ignored in reservoir simulation. All
145 the materials are assumed to be mechanically and hydraulically isotropic. The model is handled
146 through the reservoir simulator CMG-GEM; details about the model formulation, coupling scheme,
147 and validation are available elsewhere (Computer Modeling Group Ltd., 2013; Ryu et al., 2019; Tran
148 et al., 2009). The storage complex extends 12 km by 12 km in the lateral direction (49 blocks by 49
149 blocks) and 6 km in the vertical direction (48 blocks), totaling 115,248 grid blocks (Fig. 2). The grid
150 size is gradually reduced from the reservoir boundary to the center of the injection point. The grid
151 size ($dx \times dy \times dz$) near the injector is $6 \text{ m} \times 6 \text{ m} \times 20 \text{ m}$ with mesh refinement near the injection point.
152 The mesh coarseness is a balance between accuracy and computing time/output file size. Two-way
153 coupling with poroelasticity equations results in computational times much longer than fluid-flow
154 simulation only (Prevost, 2013). Each coupled simulation takes about 64 CPU hours. The lateral
155 extension is sufficiently large to avoid any mechanical boundary effects. The injection zone (IZ) is
156 100 m thick located at 3,040 m of depth. The injection zone is fully overlain by a 100 m-thick caprock.
157 The low-permeability caprock overlying the injection zone assures CO_2 containment. The five layers

158 for pressure monitoring are above the caprock and are separated by shales with a thickness of 120
 159 m. We name these layers AIZ 1 to AIZ 5 (above-injection-zone). Each AIZ layer has a thickness of 60
 160 m. The IZ and AIZs have high permeability (300 mD) and are delimited by confining layers with low
 161 permeability (100 nD). The storage complex geometry is inspired on shale-sand sequences in young
 162 sedimentary basins, such as those in the Gulf of Mexico coast (Beckham, 2018).

163 The boundaries of the IZ and the AIZ monitoring layers (the edge of this storage complex) are set to
 164 constant pressure. The top surface is free to move to capture surface heave due to strains induced in
 165 the injection zone and overburden. Only vertical displacement is allowed for the lateral surfaces in
 166 the storage complex. We simulate CO₂ injection at the reservoir center with a constant injection rate
 167 of 1,008 tons of CO₂ per day (about 0.37 Mt/year). The injector is modeled as a source term in the IZ
 168 with an equivalent radius of 0.1 m. The injection operation lasts for two years followed by one year
 169 of shut-in. The yellow dots “along the injector” in Fig. 2 represent the hypothetical location of
 170 pressure sensors vertically above the injection block, although the physical presence of the injector
 171 is not modeled.



172

173 **Fig. 2.** Reservoir geometry and boundary conditions. CO₂ is injected into the injection zone (IZ) at the depth
174 of 3,040 m. The injection zone is fully overlain by a 100-m low-permeability caprock followed by five above-
175 injection-zone (AIZ) pressure monitoring layers - all above the caprock.

176 The capillary pressure and relative permeability properties for sand and shale are available in the
177 Appendix 1. We assume isothermal conditions. The viscosity, mass density, compressibility, and
178 mutual solubilities of CO₂ and brine are calculated by the compositional module of CMG-GEM with
179 the corresponding calibrated equations of state; further details are available elsewhere (Jung et al.,
180 2020; Singh & Wheeler, 2016). The poroelasticity equations are extended to two phases within the
181 geomechanical module (Tran et al., 2004). We report liquid pressure (water) in all figures. The
182 capillary pressure is neglected in effective stress poroelastic equations in CMG-GEM. This is a
183 reasonable approximation for IZ and AIZ layers, since the capillary pressure is <1% of the in-situ
184 stress. Notice that the partially undrained loading is only relevant above the caprock in brine-filled
185 layers, so single-phase Eq. 2 still applies with $K_f = K_{brine}$. Other input parameters are listed in Table 1.
186 The assigned values aim at simulating an ideal scenario of sand-shale sequences in the Gulf of Mexico
187 Coast (Jung et al., 2018; Zheng & Espinoza, 2021). A validation of the reservoir simulation model and
188 adopted solution mesh/time step is available in Appendix 2.

189 The motivation for building a simplified model is to directly observe and characterize pressure
190 variations due to partially undrained loading induced by injection in a simple yet representative
191 model. First, we show the results of an ideal caprock fully extending over the entire injection zone so
192 pressure changes due to undrained loading can be isolated (Section 3). Then, we include possible
193 high permeability paths to differentiate increases of pore pressure caused solely by partially
194 undrained loading from fast hydraulic communication across the caprock (Section 4). The ideal
195 settings serve to capture key features of pressure changes and offer possible interpretations for
196 tracking CO₂ plume and monitoring subsurface leakages. A brief discussion for field cases is available
197 in Section 5.

Table 1. Input parameters.

Property	Symbol	IZ/AIZ (sand)	Caprock (shale)
Initial porosity [-]	ϕ	0.22	0.10
Permeability [mD]	k	300	0.0001
Young's modulus [GPa]	E	5	20
Poisson's ratio [-]	ν	0.2	0.3
Bulk modulus* [GPa]	K	2.78	16.67
Biot coefficient** [-]	α	0.92	0.54
Bulk modulus of brine [GPa]	K_f		2.2
Bulk modulus of rock matrix [GPa]	K_m		36

199

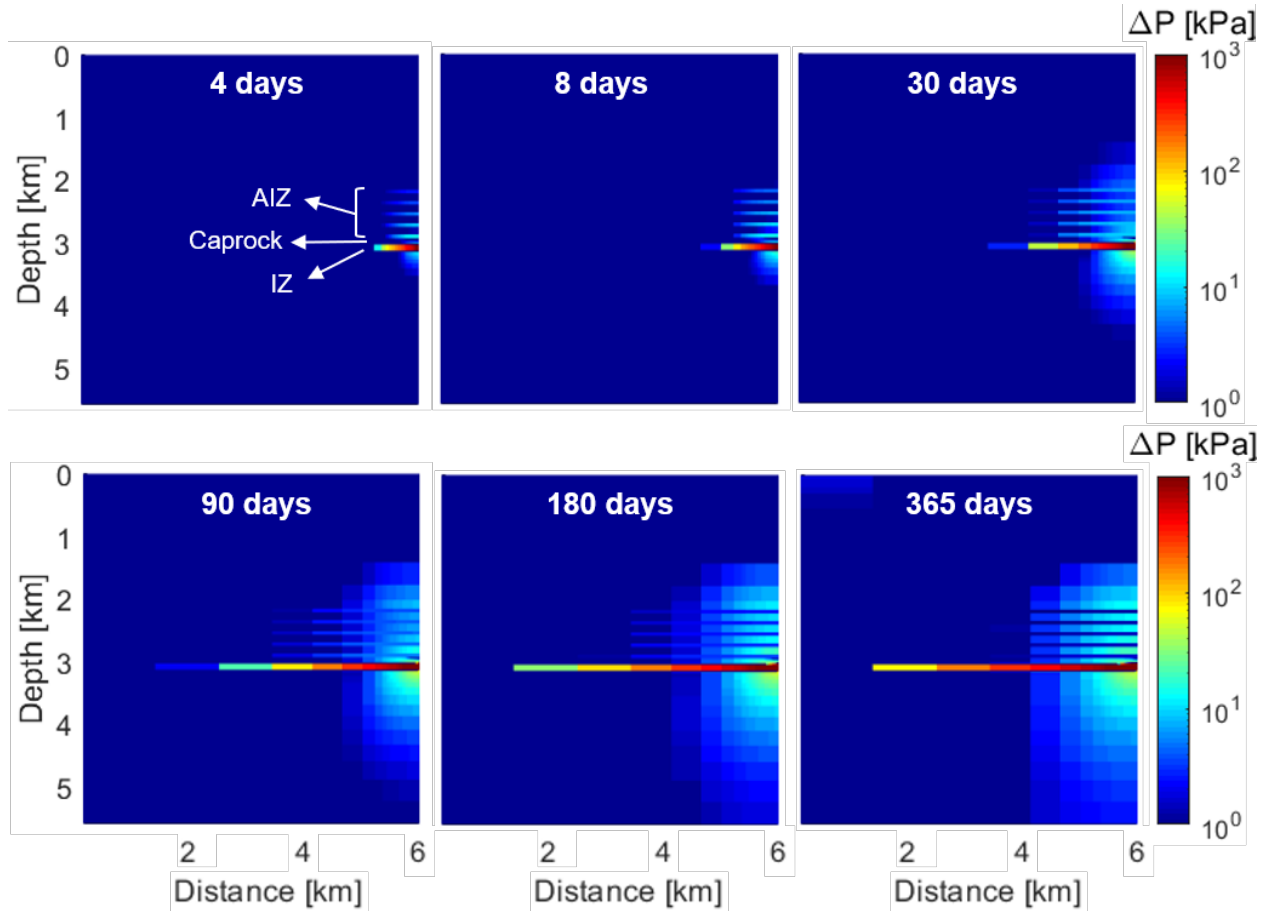
Notes: (*) $K = E/[3(1-2\nu)]$, (**) $\alpha = 1 - K/K_m$

200 3. Results

201 3.1. Pressure increases above a fully covering caprock

202 Numerical simulations show that pressure buildup from CO₂ injection in the IZ causes pore pressure
 203 changes in the storage complex, even outside the IZ, with a low permeability caprock that covers the
 204 entire injection zone (Fig. 3). The changes outside the reservoir are a result of partially undrained
 205 loading and, therefore, depend on space and time. For example, the affected region with $\Delta P > 1$ kPa
 206 extends to as far as 2 km away from the injector at $t = 365$ days. The snapshots of pore pressure
 207 change at various times demonstrate that the five AIZ permeable layers above the caprock respond
 208 to CO₂ injection in the IZ.

209 The pore pressure in overlying shales also changes. The difference between pore-pressure changes
 210 in sand (AIZ monitoring layers) and shale (caprock and other confining layers) is the result of their
 211 distinct mechanical and hydraulic properties including bulk modulus and permeability. The sand,
 212 with a lower bulk modulus, experiences a larger volumetric strain and thus a higher increase of
 213 pressure than the shale (Eq. 3). The sand drains more quickly (less than 10 days in this simulation)
 214 than the shale because of its larger hydraulic diffusivity (Eq. 4 and Fig. 3). As a result, the pressure
 215 increase due to partially undrained loading in sand presents a short-term response (~ 10 days), while
 216 the pressure increase in shale can persist for a relatively long time (> 100 days) after injection starts.

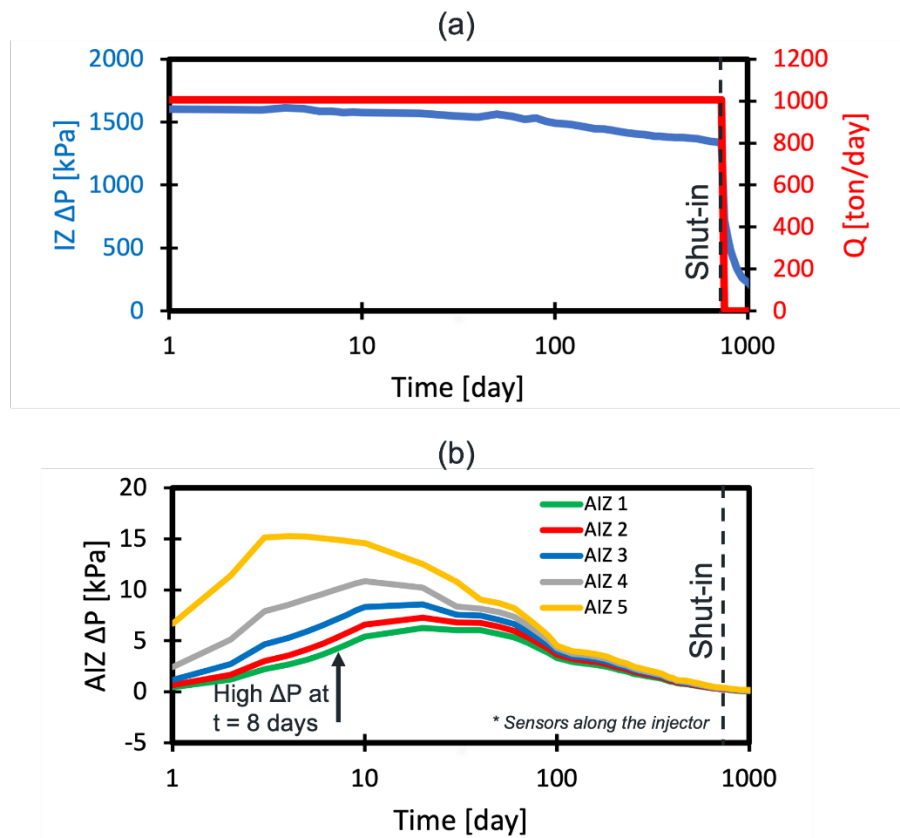


217

218 **Fig. 3.** Pore pressure changes in the CO₂ storage complex (half-domain cross-section shown because of
 219 symmetry: injector located on the right boundary). CO₂ injection increases pressure in the injection zone $\Delta P >$
 220 1,000 kPa. Partially undrained loading induced by CO₂ injection causes changes of pore pressure $\Delta P < 20$ kPa
 221 outside the reservoir layer. Pore pressure in AIZ sand layers above the fully covering caprock increases in the
 222 first 10 days to a peak value and then decreases with time. Pore pressure in shale exhibits more gradual and
 223 long-lasting changes than in sands.

224 The temporal evolution of the injection rate, IZ pressure change ΔP , and AIZ pressure change ΔP
 225 during two years of injection and one year of shut-in are closely interrelated (Fig. 4). The IZ pressure
 226 increases as much as 1,600 kPa and is followed by a gradual reduction until equilibrium to quasi-
 227 steady-state conditions while injection lasts. Instead, the pore pressure in the AIZ (along the injector
 228 and above the caprock) exhibits a transient response. The AIZ pressure increases in the first 10 days

229 and then decreases due to pressure dissipation despite continued injection. The pressure increase in
 230 the five AIZ layers above the caprock is less than 5 kPa after 100 days of injection. For example, AIZ
 231 5 (100 m above the IZ) exhibits an instantaneous response to CO₂ injection and fast pressure buildup
 232 during the initial stage of injection. A gentle decrease of pressure with time follows after reaching a
 233 peak (15 kPa) at $t = 4$ days. The pressure in other distant AIZ layers exhibits a similar trend but with
 234 a smaller amount of pressure variations and a delay in reaching the peak which increases with the
 235 distance to the injector. Hence, AIZ pressure changes are time/location-dependent and monitoring
 236 should focus on the initial stage of injection activities or during periods of changes of injection rate.



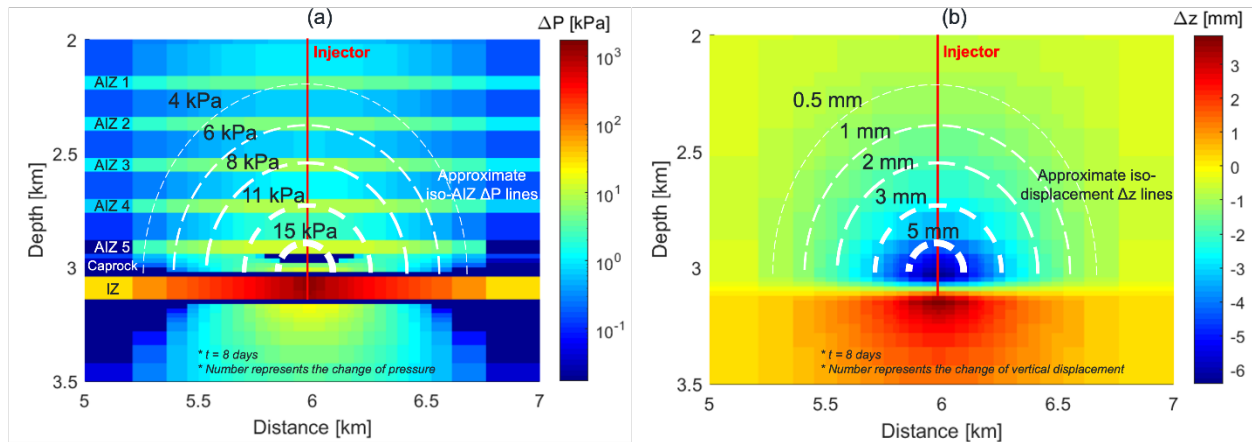
237

238 **Fig. 4.** CO₂ injection rate and pore pressure evolution with a fully covering caprock: (a) injection rate and
 239 bottom-hole pressure increase in the injection zone (IZ); (b) pressure increase above the caprock due to
 240 partially undrained loading in AIZ monitoring layers.

241 Fig. 5 shows pressure change and vertical displacement around the injector at $t = 8$ days (when the
242 maximum AIZ ΔP occurs). The AIZ ΔP is larger than 15 kPa within ~ 160 m of the injection point (the
243 distance here refers to the radial distance to the injection point). A strong ΔP signal favors an easy
244 and reliable interpretation of pressure monitoring above the caprock. The AIZ ΔP decreases more
245 quickly with increasing distance from the injector. The AIZ ΔP is less than 4 kPa when the distance is
246 larger than 880 m. The detection limit to pressure variations depends on: (1) pressure transducer
247 resolution, usually about $(\text{maximum pressure}) \times 10^{-6}$ (Santos & Silva, 2022), and (2) background
248 electrical and mechanical noise. For example, the maximum pressure resolution possible for a
249 transducer with 10^{-6} resolution rated to 100 MPa is ~ 0.1 kPa. However, other physical factors and
250 analog to digital conversion may reduce the transducer detection limits. An analog to digital
251 conversion at 16-bit results in a resolution of $(\text{maximum pressure}) / (2^{16}) \sim (\text{maximum pressure}) \times$
252 10^{-5} , i.e. 1 kPa for a 100 MPa pressure transducer. The typical amplitude of background noise in
253 standard subsurface pressure sensors is around 4 kPa (S. Hosseini et al., 2018; Wiese et al., 2013).
254 Noise is the result of several natural and artificial phenomena such as changes in atmospheric
255 pressure, ocean tides, surface precipitation, and pressure variations associated with measurement
256 instruments and equipment operation. In our generic simulated case, 4 kPa-resolution pressure
257 sensors could detect a pressure change larger than the background noise due to partially undrained
258 loading only if installed closer than ~ 880 m from the injection point. Higher precision pressure
259 transducers and signal analysis could increase the range of reliable pressure monitoring.

260 The vertical displacement induced by CO_2 injection is the highest closer to the injector (~ 6 mm at the
261 caprock/reservoir interface), which is a result of the reduced effective vertical stress in the IZ. The
262 uplift is higher than 5 mm at less than 160 m from the injection point. Fig. 5 highlights the potential
263 of poroelastic monitoring when ground surface heave (~ 0.3 mm straight above injector in this case)
264 is challenging or impossible to measure on the surface.

265

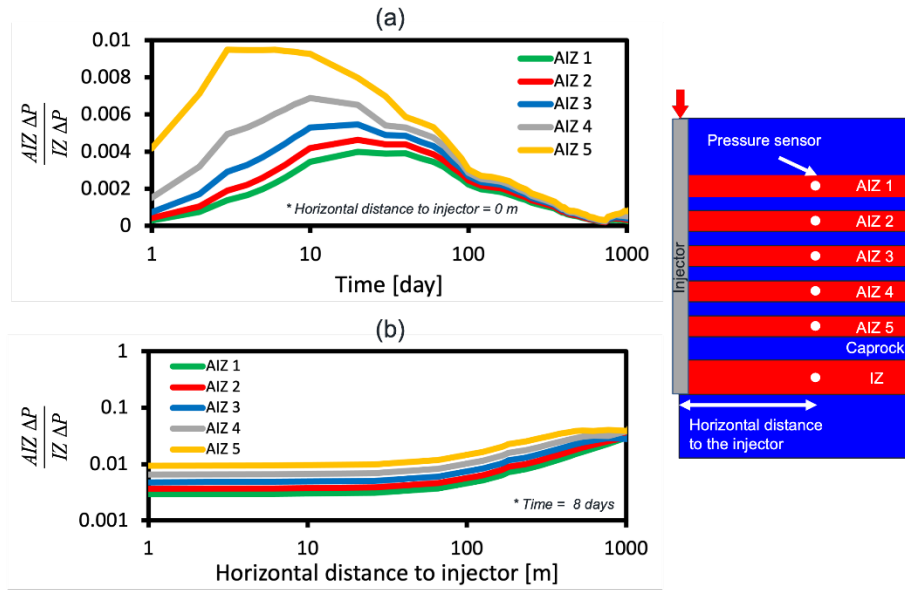


266

267 **Fig. 5.** Poroelastic response at $t = 8$ days due to CO_2 injection with a fully covering caprock: (a) pore pressure
 268 changes in the storage complex and pressure fronts around the injector – notice the logarithmic scale; (b)
 269 vertical displacement. Surface heave is negligible while pore pressure changes in permeable AIZ formations
 270 above the caprock is in the order of $\sim 10^{+1}$ kPa (iso- ΔP lines applicable to AIZ layers only).

271 **3.2. Relationship between pressure changes above the caprock and within the**
 272 **reservoir**

273 The relationship between AIZ ΔP (monitoring layers above the caprock) and IZ ΔP enables the
 274 estimation of the IZ pressure from measurements of pressure increases above the caprock. Let us
 275 examine the ratio between AIZ ΔP and IZ ΔP along the injector and plot the results as a function of
 276 time for the five AIZ permeable layers above the caprock (Fig. 6a). The ratio between AIZ ΔP and IZ
 277 ΔP reaches a peak (0.40%, 0.46%, 0.54%, 0.69%, and 0.95%) between 4 to 20 days and then
 278 decreases with time. Thus, the pressure increase above the caprock can be as large as $\sim 1\%$ of the IZ
 279 pressure increase for this selected reservoir model with a fully covering caprock and the assumed
 280 injection schedule.



281

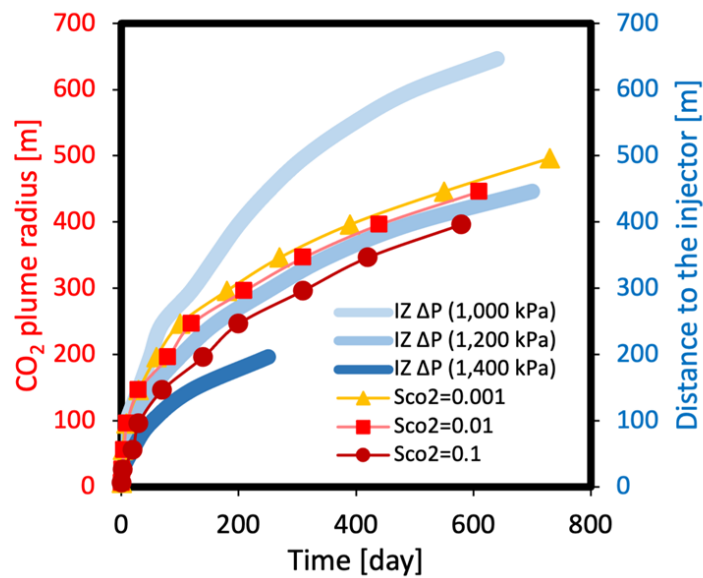
282 **Fig. 6.** Relationship between pressure above the caprock AIZ ΔP and IZ ΔP after 8 days: (1) ratio between AIZ
 283 ΔP and IZ ΔP as a function of time (sampled points along the injector); (2) ratio between AIZ ΔP and IZ ΔP as a
 284 function of horizontal distance to the injector. The maximum ratio is about 1% in the areas of interest.

285 Fig. 6b shows the ratio AIZ ΔP /IZ ΔP for pairs located at the same horizontal distance from the
 286 injector at $t = 8$ days. The ratio AIZ ΔP /IZ ΔP is nearly constant within 100 m around the injector,
 287 which indicates that this ratio does not rely much on the horizontal distance to the injector for five
 288 AIZ monitoring layers. For a distance larger than 1000 m, the ratio between AIZ ΔP and IZ ΔP is
 289 meaningless since the pressure variations in IZ and AIZ tend to be negligible.

290 3.3. Interpretation of AIZ ΔP /IZ ΔP ratio for plume migration

291 Fig. 6 demonstrates that the AIZ ΔP /IZ ΔP depends mainly on time (after injection) rather than
 292 horizontal distance to the injector (particularly when the horizontal distance is less than 100 m).
 293 Hence, variations of AIZ ΔP /IZ ΔP ratio can tell the evolution of the pressure front with time.
 294 Furthermore, the IZ pressure front is related to the saturation front (Fig. 7). Near the injector, the
 295 ratio AIZ ΔP /IZ ΔP is expected to increase, reach a maximum value, and decrease as a result of CO_2
 296 injection at constant rate (Fig. 6a). The increase of AIZ ΔP /IZ ΔP is caused by the pressurization of

297 the injection zone. The maximum AIZ ΔP /IZ ΔP depends mostly on the imposed rock deformation
 298 and poroelastic properties (Eq. 3). The time for the maximum ratio AIZ ΔP /IZ ΔP occurs between 4
 299 and 20 days in our model (Fig. 6a). The CO₂ plume is ~40 m away from the injector at the peak in AIZ
 300 5 (4 days) and 96 m away at the peak in AIZ 1 (20 days) (Fig. 7). The AIZ ΔP /IZ ΔP decrease rate
 301 depends on the hydraulic diffusivity of the AIZ. Values of AIZ ΔP /IZ ΔP cannot be larger than the peak
 302 in the absence of a high permeability path between the IZ and AIZ layers above the caprock. IZ ΔP can
 303 be approximated from analytical solutions or reservoir simulations with known bottom-hole
 304 pressure – See Appendix 2 (Avci, 1994; Benson & Doughty, 2006).



305
 306 **Fig. 7.** CO₂ plume radius: the migration of CO₂ plume is tracked through CO₂ saturation. The 1,200 kPa
 307 pressure front in the IZ moves simultaneously with the CO₂ plume for a constant injection rate.

308 4. Discussion: detection of subsurface high permeability paths

309 4.1. Presence of a high-permeability fault

310 The previous section highlights that pressure increases above the caprock are possible during CO₂
 311 injection in a reservoir in the absence of any high permeability paths connecting the injection zone
 312 and permeable formations above the caprock. The cause is deformation of the rock and relatively fast

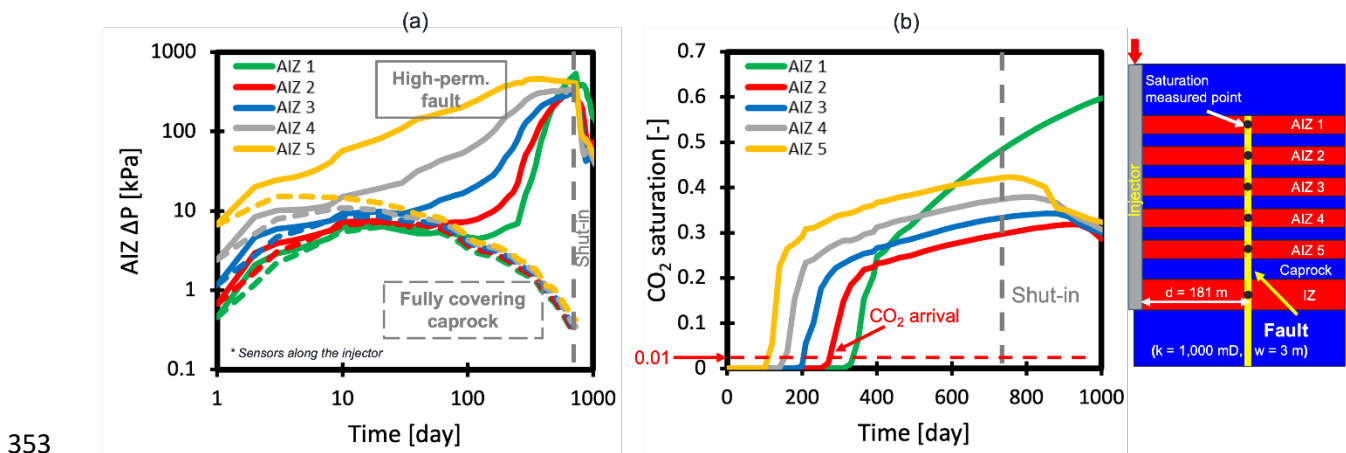
313 compression of the pore fluid. As an extension of our base case with a fully covering low-permeability
314 caprock, let us consider the existence of a fault with high permeability and its influence on the AIZ
315 pore pressure above the caprock. A high permeability fault is set at a distance of 181 m from the
316 injector. The fault intersects all AIZ layers and shales in between spanning over 980 m of vertical
317 length. We model the fault as a wall of grid blocks with a width of 3 m and volume-average
318 permeability equal to 1,000 mD (Childs et al., 2007; Faulkner et al., 2010; Tao et al., 2012; Zheng &
319 Espinoza, 2021b). Fig. 8a compares the pressure increase in five AIZ layers monitored along the
320 injector and the base case.

321 The pressure increase in AIZ layers above the caprock with a fully covering caprock (base case) is the
322 result of partially undrained loading. However, the AIZ pressure increase in the presence of a high-
323 permeability fault is the result of the combined effects of direct and fast hydraulic communication,
324 and partially undrained loading (Eq. 1). The key features in Fig. 8a include:

- 325 • The presence of a high permeability path favors more gradual increases of pore pressure to
326 higher peak values in AIZ layers until injection shut-in (2 years) than the base case (Fig. 6).
327 This additional and sustained pressure increase is the result of fluid communication between
328 the IZ and the AIZ layers above the caprock through the fault.
- 329 • The pressure trends in the base and high-permeability fault cases overlap with each other in
330 the first 10 days of CO₂ injection before the effects of partially undrained loading reaches the
331 maximum value. After that, the pressure deviation between the two cases gradually becomes
332 more and more significant. The AIZ ΔP in presence of a high-permeability fault is one order
333 of magnitude larger than the base case after one year of injection. Direct fluid communication,
334 hence, increases AIZ pore pressure ten times more than partially undrained loading after 2
335 years.

336 • The pressure buildup due to the hydraulic communication takes time. This is a function of the
 337 hydraulic diffusivity of the reservoir rock and high permeability features across the caprock.
 338 For example, it takes 26 days for achieving a pressure increase of 100 kPa in AIZ 5 (closest to
 339 the injection point) and more than 160 days in the other AIZs for the same pressure imcrease.
 340 Thus, more distant regions exhibit a longer delay in pore pressure increase. The time delay
 341 in sensing the pressure increase at different monitoring points helps assess caprock integrity.

342 Pressure increase larger than expected by sole partially undrained unloading implies fluid transfer
 343 (e.g. brine) across the caprock or a sealing fault, but does not necessarily mean a CO₂ leak. Let us also
 344 monitor the evolution of CO₂ saturation along the fault. The negligible caprock dip (assumed in this
 345 generic model) and buoyancy of bulk CO₂ leads to the rise of CO₂ through the fault and AIZ layers, and
 346 thus the pressure in uppermost AIZ 1 is higher than the pressure in other AIZs after two years of CO₂
 347 injection. Here we define the CO₂ arrival at a specific AIZ when CO₂ saturation at the measured point
 348 is higher than 0.01. The CO₂ arrival time for five AIZs is 100, 140, 200, 250, 310 days (Fig. 8b). Thus,
 349 leakage detection through direct CO₂ saturation monitoring (e.g., through fluid sampling or neutron
 350 and resistivity logs) requires at least several months. The AIZ pressure increase occurs much before
 351 the change of CO₂ saturation and provides earlier warnings than compositional monitoring at a
 352 potential observation well near the fault.



354 **Fig. 8.** Time evolution of pore pressure and CO₂ saturation above the caprock in the presence of a high-
355 permeability fault: (a) pressure increase in five AIZ layers along the injector, including the base case with a
356 fully covering caprock and the case with a high-permeability fault; (b) CO₂ saturation in five AIZ layers along
357 the fault. A high-permeability fault results in steady and higher increases of pressure in AIZ layers above the
358 caprock than in the base case.

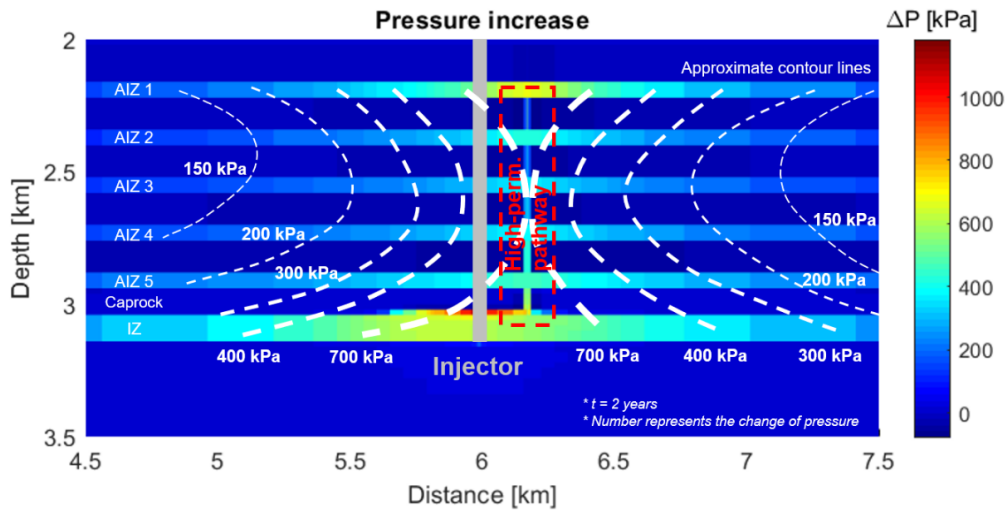
359 The CO₂ arrival time can also be approximated with analytical equations (See Appendix 2). For
360 example, for steady-state single phase radial fluid flow the piston-like injection front radius R is a
361 function of time t :

$$362 \quad R = \sqrt{\frac{Q_{eff}}{\pi h} t} \quad (5)$$

363 where Q_{eff} is the injection volumetric flow rate and h is the reservoir thickness. CO₂ injection in brine
364 results in poor sweep efficiency, hence the injection rate can be modified to $Q_{eff} = Q/\psi$, where Q is the
365 actual injection rate and ψ is the volume-time average sweep efficiency factor. Typical sweep
366 efficiency factors for CO₂ in oil reservoirs range from 0.20 to 0.28 for 1 pore volume (Lake et al., 2019).
367 Direct comparison of numerical simulations with Eq. 5 results in a reasonable approximation for the
368 CO₂ plume radius as a function of time with $\psi = 0.01$ to 0.015 (Fig. 7). The low value of ψ captures
369 CO₂ high mobility, buoyancy and low solubility in water. Eq. 5 also predicts that CO₂ should arrive to
370 the fault at $R = 181$ m, at $t = 71$ -107 days (with $\psi = 0.01$ to 0.015) in agreement with the CO₂ arrival
371 ($S_{CO_2} = 0.01$) at AIZ 5 at $t \sim 105$ days shown in Fig. 8b.

372 The pressure distribution shown in Fig. 9 is the result of a high-permeability fault (compare to the
373 base case in Fig. 5a). The high-permeability path releases pressure from the injection zone and
374 exhibits the highest AIZ ΔP in each AIZ. The AIZ ΔP decays with the increase of distance to the high-
375 permeability fault. A rough estimation of the leakage location is possible through pressure
376 monitoring and mapping above the caprock. In this case, the estimated location of the high-
377 permeability path based on the perturbations of pore pressure is about 180 m away from the injector,

378 which coincides with the actual fault location (the fault location has the highest AIZ ΔP in each
 379 monitoring layer). An increase of the number of monitoring wells is expected to provide useful
 380 information on the estimation of the extent of subsurface leakages (Zeidouni & Pooladi-Darvish,
 381 2012b). The objective of this paper is to explore the pressure signals above the caprock for different
 382 subsurface leakage scenarios through forward modeling (see also next subsections). Though, this
 383 simple example could be extended into a formal inverse problem to detect high-permeability
 384 pathways with unknown location and arbitrary geometry. Geostatistical data-space approaches and
 385 deep-learning algorithms have been used to locate leaks through leaky wellbores considering
 386 hydraulic communication only or simplified overburden mechanical models (Sun & Durlofsky, 2019;
 387 Tang et al., 2021).



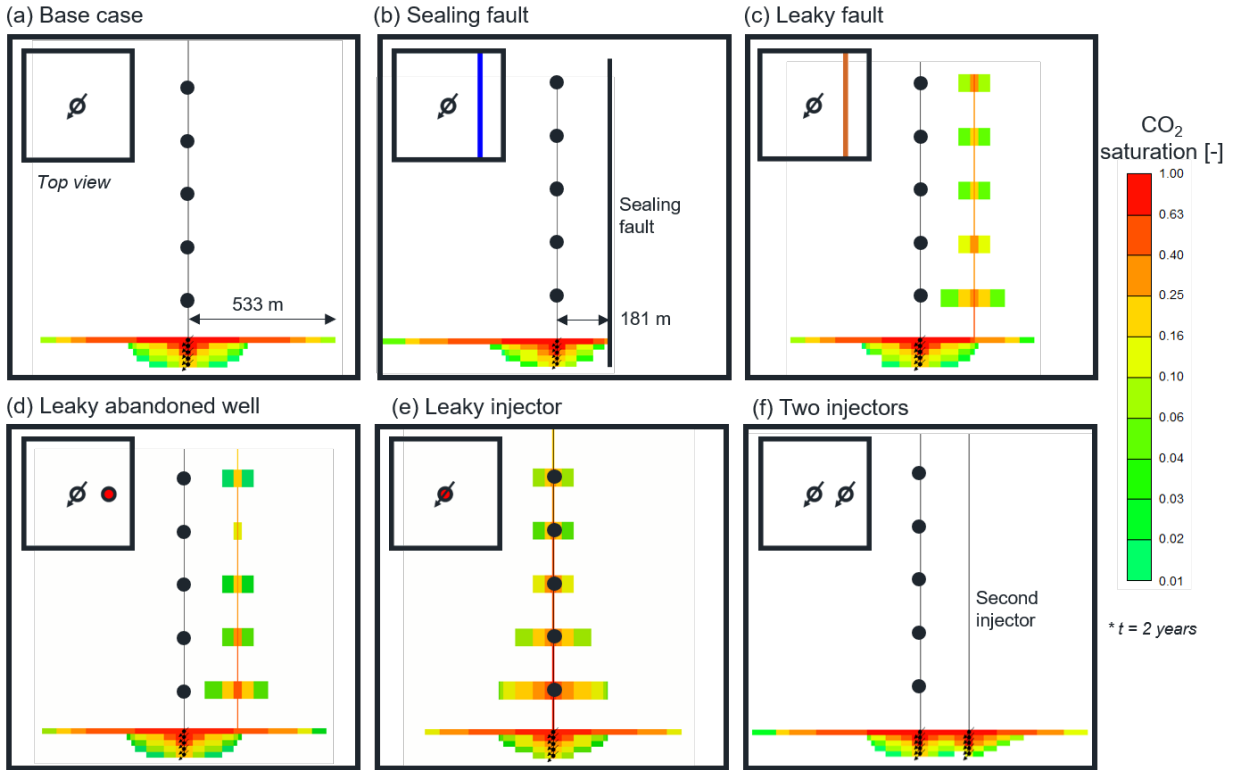
388 **Fig. 9.** Pressure change in permeable monitoring layers above the caprock in the presence of a high-
 389 permeability fault. The red dashed box highlights the location of the estimated high-permeability path based
 390 solely on the observed field pore pressure, which coincides with the location of the high-permeability fault.
 391

392 **4.2. Other relevant scenarios**

393 In this section, we discuss the pressure increases above the caprock in other relevant subsurface
 394 scenarios. Fig. 10 presents the distribution of CO₂ plume after two years of injection in six different

395 cases, including (a) base case with a low-permeability caprock covering all the injection zone, i.e., no
396 fast hydraulic communication or leaks, (b) case with a sealing fault, (c) case with a leaky fault, (d)
397 case with a leaky abandoned well, (e) case with a leaky injector, and (f) case with two injectors. The
398 leaky fault, the sealing fault, the leaky abandoned well, and the second injector are placed at a
399 distance of 181 m from the primary injector. The effective (volume average) permeability of all the
400 leaky grid blocks is 1,000 mD with a thickness of 3 m. The fault permeability has three different values
401 ($k_{fault} = 10, 100, \text{ and } 1,000 \text{ mD}$) in the leaky fault case for a sensitivity test. The second injector starts
402 after 1 year at the same rate of the first injector, up to 1008 ton/day, until the end of the simulation
403 (2 years). Multiple wells are generally used to maximize the available storage space and increase
404 spatial sweep efficiency (Lake et al., 2014; Sun & Durlofsky, 2019). Layer AIZ 1 is overlain by a thick
405 fully covering secondary caprock. The black dots along the primary injector in Fig. 10 represent the
406 location of pressure monitoring sensors.

407 The CO₂ plume radius is 533 m after 2-years in the base case (cut-off $S_{CO_2}=1\%$ - Fig. 10a). The sealing
408 fault inhibits CO₂ flow on one side and results in preferential CO₂ plume migration opposite to the
409 fault location (Fig. 2b). The presence of leaks reduces the CO₂ plume reach in all leaky cases. High
410 saturation around the leaky well of Fig. 10d in AIZ 5 to 3 is caused by proximity to the injected layer,
411 while high saturation in AIZ 1 is caused by accumulation of CO₂ by buoyancy. AIZ 2 exhibits low
412 saturation because is neither close to the injected layer nor the top layer. Case (d) has been studied
413 previously with focus on pressure time-derivative analysis to discriminate the influence of partially
414 undrained loading from hydraulic communication (Zeidouni & Vilarrasa, 2016). The CO₂ plume reach
415 is the shortest (only 427 m) in the leaky injector case (Fig. 10e).



416

417 **Fig. 10.** Distribution of CO₂ plume after two years of CO₂ injection in different scenarios: (a) base case (no
 418 leaks through the caprock); (b) case with a sealing fault; (c) case with a leaky fault; (d) case with a leaky
 419 abandoned well; (e) case with a leaky injector; and (f) case with two injectors. The inserted plot at the top left
 420 of each sub-figure represents the schematic top-view of each layout.

421 Fig. 11 shows the AIZ pressure increase for the different cases shown in Fig. 10. The presence of high
 422 permeability pathways results in the AIZ pressure change in the range of 100 to 1,000 kPa, while
 423 pressure increase due to partially undrained loading is characterized by lower values (in the order
 424 of magnitude of 10 kPa). All cases with high-permeability pathways lead to eventual CO₂ leaks in our
 425 ideal models with no caprock dip. Strong hydraulic communication with no CO₂ leaks could be
 426 possible, for example, injecting CO₂ near the top of an anticline with a high-permeability fault
 427 downdip not reached by the CO₂ plume.

428 The leaky injector has the most significant effect on pore pressure changes along the well compared
 429 with other leaky scenarios. The leaky abandoned well is 181 m away from the injector and thus

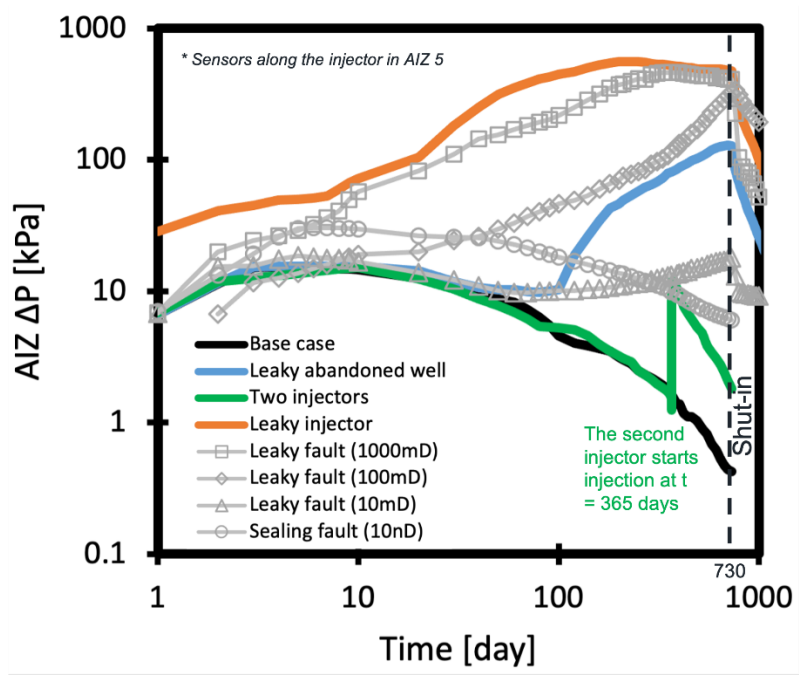
430 exhibits a delay in pressure increase compared with the leaky injector case. The response for the
431 leaky abandoned-well case overlaps with the response for the base case at the initial stage ($t < 90$
432 days), suggesting direct fluid flow has not yet arrived at the abandoned well and the primary reason
433 for pressure change is due to partially undrained loading. Afterward, continuous hydraulic
434 communication leads to faster and higher pressure increases.

435 Variations in fault permeability can result in distinct responses in the AIZ. A permeable fault favors
436 faster fluid communication and higher AIZ pressure increase than the fault with lower permeability.
437 The pressure increase is one order of magnitude smaller for the case with $k_{fault} = 10$ mD than for k_{fault}
438 $= 1,000$ mD. However, if the fault permeability is small enough to inhibit fluid flow (for example, 10
439 nD), structural sealing will favor a stronger undrained loading above the reservoir and thus higher
440 pressure increase above the caprock (as large as 30 kPa) than the base case with no sealing fault and
441 no leaks.

442 The addition of the second injector after 1 year results in increases of ΔP by 12 kPa in the first five
443 following days, as a result of partially undrained loading caused by the injection process. The increase
444 of pressure induced by undrained loading follows the principle of superposition (Roussel & Agrawal,
445 2017), consistently with the assumed linear poroelastic behavior of the rocks. This increase is
446 relatively small compared to changes caused by direct hydraulic communication, yet measurable.
447 Understanding distinct features of pressure increase with or without leaks can help quantify caprock
448 sealing and identify high permeability paths across the caprock.

449 The transient poroelastic response in the field depends on fluid injection rate and injection schedule.
450 A large injection rate entails fast pressure buildup in the IZ and thus triggers a strong pressure
451 response in the AIZ. For a given injected volume, a step-wise increase of injection rate will mitigate
452 the pore pressure increase from partially undrained loading as increases of volumetric strain happen
453 at the same time pore pressure dissipates in the AIZ. For example, the pressure ramp-up period

454 should be smaller than ~10 days in our base case to induce a noticeable peak and decay of the
 455 pressure signal by partially undrained loading in the AIZ monitoring layers.



456

457 **Fig. 11.** Pore pressure increases above the caprock for different storage scenarios shown in Fig. 10. The fault
 458 permeability varies from 10 nD to 1,000 mD. The effective permeability of leaky blocks in other leaky
 459 scenarios is 1,000 mD.

460 Another possible scenario is a highly compartmentalized and relatively small reservoir. No-flow
 461 boundary conditions have a direct impact on pressure in the injection zone and therefore in AIZ
 462 layers. Typically, pressure gradients within the reservoir are small under compartmentalized
 463 conditions and pressure can remain high over long periods of time after injection shut-in. Such
 464 pressure response in the IZ would result in a less pronounced yet more enduring pressure increase
 465 in the AIZ assuming a fully-covering caprock. The reservoir model used in this paper is sufficiently
 466 large so that the difference between constant pressure or no-flow boundary condition (i.e.,
 467 compartmentalized) is negligible on AIZ ΔP for ~1008 ton/day injection rate over 2 years.

468 5. Comparison of generic simulation results with field data

469 There are four CO₂ injection field cases published so far that document pressure monitoring above
470 the injection zone: Cranfield (USA), Ketzin (Germany), Otway (Australia), and Decatur (USA) (Bauer
471 et al., 2016; Ennis-King et al., 2017; Kim & Hosseini, 2014; Wiese et al., 2013). The first two involve
472 pressure monitoring above the caprock similar to the generic model simulated in this study. The last
473 two measure pressure above the injection point but within the same injection unit, such that, thin
474 low permeability layers exist between the injection point and the pressure sensors but there is no
475 thick and continuous low-permeability caprock separating the pressure sensors from the injection
476 point. We include these two most recent field cases in the following summary for the sake of
477 completeness and comparison, although our model is meant to be compared with cases that measure
478 pressure above the caprock.

- 479 • *Cranfield, United States, 2009-2011* (Kim & Hosseini, 2014; Tao et al., 2012): CO₂ was injected
480 in a sandstone with a three-step rate schedule. Reservoir (IZ) pressure change reached a
481 maximum of ~8.8 MPa after 250 days of injection. Pore pressure changes are available for
482 two monitoring wells in permeable layers above a ~120 m-thick caprock. The pressure
483 signal of wellbore 31F-2 (68 m down-dip) shows an initial increase of 50-150 kPa followed
484 by a steady increase of 100 kPa, totaling AIZ ΔP / IZ ΔP ~ 0.028. The pressure signal of
485 wellbore 31F-3 (132 m down-dip) shows spikes up to 50 kPa which coincide with changes
486 of injection rate and rapid dissipation (5-20 days), totaling AIZ ΔP / IZ ΔP ~ 0.006. Using Fig.
487 11 as a guide permits concluding the following: (1) the steady and relatively high pressure
488 increase in well 31F-2 indicates that there might have been hydraulic communication
489 through the caprock along this vertical well, and (2) relatively small pressure spikes indicate
490 full caprock sealing along well 31F-3. None of these cases point necessarily to a CO₂ leak,
491 since the wells are downdip the injection well and there is no field evidence of capillary

492 sealing breakthrough (Espinoza & Santamarina, 2017). Temperature variations along the
493 wells might have also affected pressure readings (Lindeberg, 2011).

494 • *Ketzin, Germany, 2011-2012* (Wiese et al., 2013): CO₂ was injected in well Ktzi 201 for over
495 8 months with a prescribed constant rate interrupted sporadically. Reservoir IZ bottom-hole
496 pressure increased ~0.5 MPa. Monitoring well P300 measured pressure 215 m above
497 injection zone and 120 m updip in the first permeable layer above the caprock. AIZ
498 monitoring showed steady pressure increase reaching a maximum of 7.5 kPa, i.e., AIZ ΔP / IZ
499 $\Delta P \sim 0.015$. The original paper does not offer conclusive proofs for the steady rise in
500 pressure above the caprock and does not discard the possibility of strong hydraulic
501 communication. In fact, there are faults ~2 km away from the injector and monitoring wells
502 behind a dome. A cursory comparison with Fig. 11 indicates hydraulic communication likely
503 through the faults since the monitoring well does not go through the caprock. A CO₂ leak is
504 not a direct implication of hydraulic communication because the injection volume is small
505 and the fault system is mostly behind a dome within the reservoir layer.

506 • *Decatur, United States, 2011-2014* (Bauer et al., 2016): CO₂ injection was performed at well
507 CCS1 over nearly 3 years at a constant injection rate and close to the bottom of Mt. Simon
508 Formation (sandstone with embedded thin shale layers). As a result, bottomhole pressure
509 at the injector (IZ) changed within ~1 month up to 3.4 MPa at the depth of injection.
510 Additional pressure monitoring above the injection depth but within the Mt. Simon
511 Formation and below the Eau Claire Shale caprock registered steady increases of up to 0.35
512 MPa in well VW1 within the Mt. Simon Sandstone. This is about 0.10 of the IZ ΔP . The original
513 paper concludes that there is good hydraulic communication between the injection and
514 measured points in agreement with previous expectations and our numerical simulations
515 (Fig. 11). Rapid hydraulic communication is likely due to discontinuities of thin shale layers

516 within the Mt. Simon Formation, which is capped by the Eau Claire shale and provides
517 further assurance of CO₂ storage.

518 • *Otway, Australia, 2015-2016* (Ennis-King et al., 2017): CO₂ was injected in the Paarette A
519 Formation with a target injection rate of ~150 tons/day for over 150 days with sporadic
520 shut-ins at the CO2CRC Otway site in South-West Victoria, Australia. The bottom-hole
521 pressure reached quickly $\Delta P = 0.2$ MPa after injection started or resumed. Pressure
522 monitoring above the injection point exhibited gradual changes of up to 35 kPa well
523 correlated with injection starting/resuming times. This is 0.175 of the pressure at the
524 injection point. This strong hydraulic communication is not surprising since pressure
525 changes are within the same permeable storage unit and under the caprock. In fact, CO₂
526 plume migration interpreted from time-lapse seismic suggests the presence of a
527 transmissive fault ~300 m away from the injector (Dance et al., 2019).

528 6. Conclusions

529 This paper presents numerical simulation results of CO₂ injection and corresponding pore pressure
530 changes above the caprock due to partially undrained loading and hydraulic communication, in views
531 of CO₂ plume tracking and leak monitoring in CO₂ geological storage. The simplified model in this
532 paper serves as an ideal case of pressure monitoring in a sand-shale sequence and aims at providing
533 general trends, although each actual site possesses its own particularities and complexities that may
534 impact those trends. Yet, the results shed light on the general characterization and validation of
535 pressure signals above the caprock as a result of injection-induced poroelastic effects, provide rapid
536 guidelines for analyses of field cases, and serve as validation to build specific models for a given field
537 case geometry, rock properties, and injection schedule. The major conclusions of this paper are:

538 • Reduced effective stress at the reservoir/storage unit induced by CO₂ injection results in
539 surface heave as well as rock deformation between the injection layer and the ground surface.

540 A pore pressure variation due to rock deformation and formation fluid compression may
541 appear above the caprock as a result of partially undrained loading.

542 • The pore pressure increase induced by partially undrained loading above the caprock is non-
543 negligible. The pressure increase is up to 1% of the injection zone (IZ) pressure increase for
544 the chosen storage complex. Pressure increase above the caprock due to partially undrained
545 loading is maximum when rapid changes of pressure occur in the IZ, such as in the initial
546 stage of injection for a constant injection rate schedule, or when injection resumes after a
547 shut-in period. Since the pressure in the injection zone is linked to the migration of the CO₂
548 plume, it is possible to use pressure changes above the caprock to track the migration of the
549 CO₂ plume in the injection zone.

550 • High permeability paths across the caprock can increase pressure change above the caprock
551 by one order of magnitude compared to the base case with a fully covering caprock (from
552 ~15 kPa in the base case to 100-1,000 kPa). Such distinctive response is useful to discern
553 pressure changes caused solely by rock compression from pressure changes caused by a high
554 permeability path through the caprock.

555 • The comparison of generic trends with field cases suggest that: (1) Cranfield monitoring well
556 31F-3 showed a pressure response above the caprock similar to our simulated base case with
557 no fluid transfer across the caprock, (2) Ketzin monitoring well P300 showed a pressure
558 change above the caprock compatible with fair hydraulic communication between the
559 reservoir and the caprock, and (3) two other cases of monitoring above the injection point
560 within the same injection zone show high hydraulic communication, as expected. A tailored
561 simulation for each case is needed to confirm these cursory interpretations.

562 • Pressure monitoring above the caprock can be an effective technique to track the extent of
563 the CO₂ plume, quantify hydraulic communication, detect potential leaks, and provide earlier

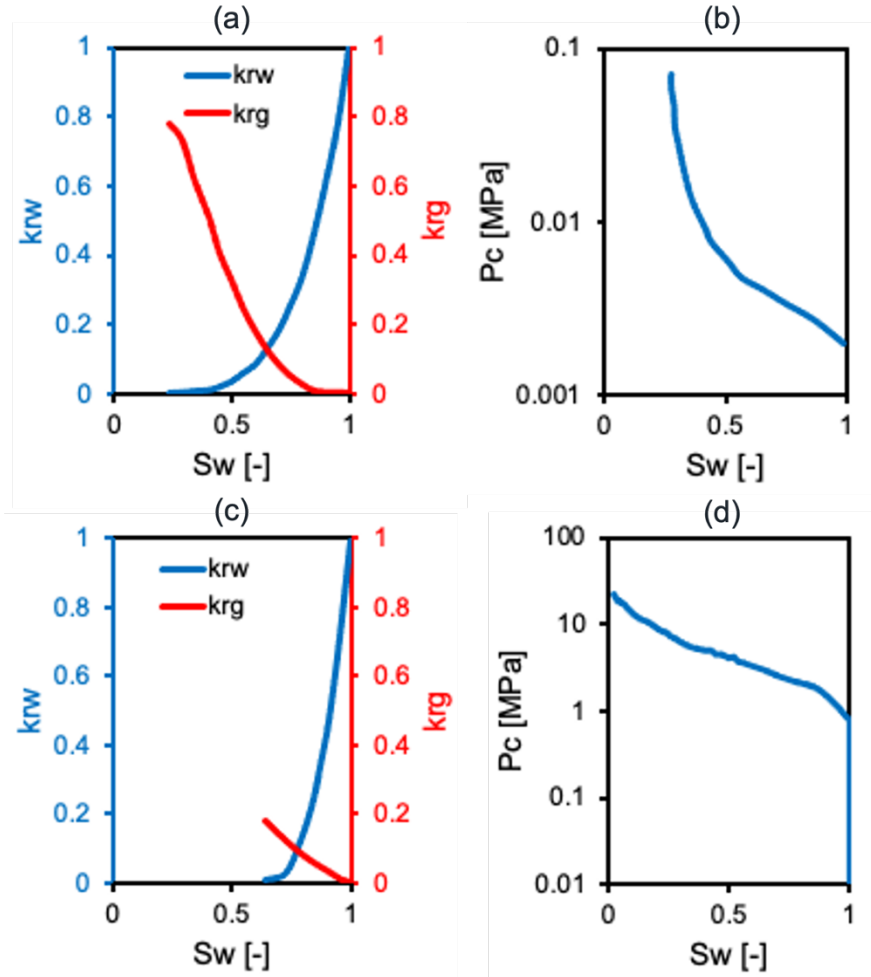
564 leak warnings than compositional fluid monitoring. Unexpected pressure increases above the
565 caprock (higher than the range expected for partially undrained loading) are an indication of
566 non-negligible hydraulic communication from the injection zone into overlying formations.

567 Acknowledgments

568 The authors are thankful to the Dr. Cécile DeWitt-Morette France-UT Endowed Excellence Fund for
569 making possible this study. We are also grateful to anonymous reviewers who helped us highlight
570 the novelty of this paper and better explain the results.

571 Appendix 1: Capillary pressure and relative permeability

572 The capillary pressure in sand is converted from J-functions measured with an air-mercury system
573 to a CO₂-brine system. The relative permeability curve in sand is calculated through the Brooks-Corey
574 drainage model (Jung et al., 2018) (Fig. A1a and Fig. A1b). The capillary pressure and the relative
575 permeability for shale are adapted from the literature and shown in Fig. A1c and Fig. A1d (Bennion
576 & Bachu, 2008; Ren et al., 2016).



577
578

Fig. A1. Capillary pressure and relative permeability in the model: sand (a) and (b); shale (c) and (d).

579 Appendix 2: Model validation

580 We validated our numerical model against an analytical solution which combines mass balance for
581 radial flow and multiphase Darcy's law (Benson & Doughty, 2006; Tsopele et al., 2022). The increase
582 of pressure ΔP in the injection zone (IZ) as a function of distance to the injector and time is

$$583 \quad \Delta P = \frac{Q\mu_{brine}}{4\pi kh} W + \frac{Q\mu_{CO_2}}{2\pi kh} \left(\ln \frac{r_f}{r_w} + \left(\frac{f_{CO_2}}{k_{r_{CO_2}}} \Big|_{r_f} - 1 \right) \left(1 - \frac{r_w}{r_f - r_w} \ln \frac{r_f}{r_w} \right) \right)$$

584 where

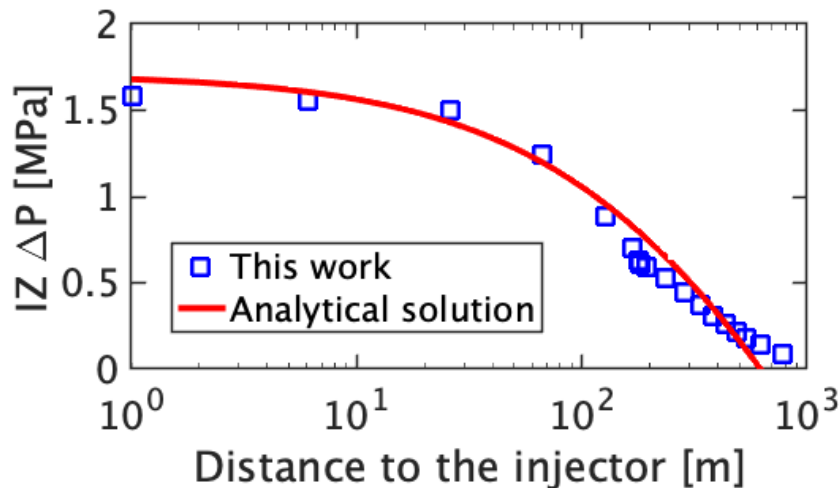
$$585 \quad W = -0.5772 - \ln(u_f)$$

$$586 \quad u_f = \frac{\phi \mu_{brine} C_t r_f^2}{4kt}$$

587
 588
 589
 590
 591
 592
 593
 594
 595
 596
 597
 598
 599

$$r_f = \left(\frac{Qt}{\pi h \phi S_{CO_2}} \right)^{1/2}$$

Here Q is the injection rate (m^3/s), t is the injection time (s), μ_{CO_2} is the CO_2 viscosity ($Pa \cdot s$), μ_{brine} is the brine viscosity ($Pa \cdot s$), k is the injection zone permeability (m^2), h is the injection zone thickness (m), ϕ is the injection zone porosity, C_t is the injection zone compressibility ($1/Pa$), r_w is the distance to the injector (m). At the CO_2 front, r_f is the radius of the CO_2 front (m) and S_{CO_2} is the average CO_2 saturation at the CO_2 front, which is indicated in Fig. 7a. f_{CO_2} is the CO_2 fractional flow at the CO_2 front, which is obtained through the Buckley-Leverett equation (Peters, 2012). k_{rCO_2} is the CO_2 relative permeability at the CO_2 front, which is calculated through the Corey-type equation as $k_{rCO_2} = k_{rCO_2}^0 \left(\frac{S_{CO_2}}{1-S_{rb}} \right)^n$ (Burton et al., 2009), where S_{rb} is the irreducible brine saturation and $k_{rCO_2}^0$ is the CO_2 relative permeability at the irreducible brine saturation. The capillary pressure and the relative permeability information can be found in Fig. A1. Fig. A2 shows the IZ pressure increase obtained by the numerical model and mesh adopted in this paper compares well to the analytical solution.



600
 601
 602
 603

Fig. A2. Comparison of the numerical and the analytical solutions for pressure increase in the AIZ at time = 8 days.

604 References

- 605 Ajo-Franklin, J. B., Peterson, J., Doetsch, J., & Daley, T. M. (2013). High-resolution characterization of a
606 CO₂ plume using crosswell seismic tomography: Cranfield, MS, USA. *International Journal of*
607 *Greenhouse Gas Control*, 18, 497–509. <https://doi.org/10.1016/j.ijggc.2012.12.018>
- 608 Arts, R., Eiken, O., Chadwick, A., Zweigel, P., van der Meer, L., & Zinszner, B. (2004). Monitoring of CO₂
609 injected at Sleipner using time-lapse seismic data. *Energy*, 29(9), 1383–1392.
610 <https://doi.org/10.1016/j.energy.2004.03.072>
- 611 Avci, C. B. (1994). Evaluation of flow leakage through abandoned wells and boreholes. *Water Resources*
612 *Research; (United States)*, 30:9. <https://doi.org/10.1029/94WR00952>
- 613 Bauer, R. A., Carney, M., & Finley, R. J. (2016). Overview of microseismic response to CO₂ injection into
614 the Mt. Simon saline reservoir at the Illinois Basin-Decatur Project. *International Journal of*
615 *Greenhouse Gas Control*, 54, 378–388. <https://doi.org/10.1016/j.ijggc.2015.12.015>
- 616 Beckham, E. C. (2018, May). *CO₂ storage in deltaic environments of deposition : integration of 3-*
617 *dimensional modeling, outcrop analysis, and subsurface application* (Thesis).
618 <https://doi.org/10.15781/T26970G0Z>
- 619 Bennion, B., & Bachu, S. (2008). Drainage and Imbibition Relative Permeability Relationships for
620 Supercritical CO₂/Brine and H₂S/Brine Systems in Intergranular Sandstone, Carbonate, Shale,
621 and Anhydrite Rocks. *SPE Reservoir Evaluation & Engineering*, 11(03), 487–496.
622 <https://doi.org/10.2118/99326-PA>
- 623 Benson, S., & Doughty, C. (2006). Estimation of field-scale relative permeability from pressure transient
624 tests. *Proceedings, EPA CO₂SC Workshop, Berkeley, CA: Lawrence Berkeley National Laboratory.*

625 Burton, M., Kumar, N., & Bryant, S. L. (2009). CO2 injectivity into brine aquifers: Why relative
626 permeability matters as much as absolute permeability. *Energy Procedia*, 1(1), 3091–3098.
627 <https://doi.org/10.1016/j.egypro.2009.02.089>

628 Cheng, A. H.-D. (2016). *Poroelasticity*. Springer International Publishing. <https://doi.org/10.1007/978-3->
629 319-25202-5

630 Childs, C., Walsh, J. J., Manzocchi, T., Strand, J., Nicol, A., Tomasso, M., et al. (2007). Definition of a fault
631 permeability predictor from outcrop studies of a faulted turbidite sequence, Taranaki, New
632 Zealand. *Geological Society, London, Special Publications*, 292(1), 235–258.
633 <https://doi.org/10.1144/SP292.14>

634 Cihan, A., Birkholzer, J. T., & Zhou, Q. (2013). Pressure buildup and brine migration during CO2 storage in
635 multilayered aquifers. *Ground Water*, 51(2), 252–267. <https://doi.org/10.1111/j.1745->
636 6584.2012.00972.x

637 Computer Modeling Group Ltd. (2013). *Compositional & Unconventional Reservoir Simulation*. Calgary.

638 Coussy, O. (2004). *Poromechanics*. John Wiley & Sons.

639 Dance, T., LaForce, T., Glubokovskikh, S., Ennis-King, J., & Pevzner, R. (2019). Illuminating the geology:
640 Post-injection reservoir characterisation of the CO2CRC Otway site. *International Journal of*
641 *Greenhouse Gas Control*, 86(C). <https://doi.org/10.1016/j.ijggc.2019.05.004>

642 Detournay, E., & Cheng, A. H. D. (1993). Fundamentals of poroelasticity, 113–171.
643 <https://doi.org/10.1016/b978-0-08-040615-2.50011-3>

644 Detournay, E., & Cheng, A. H.-D. (1988). Poroelastic response of a borehole in a non-hydrostatic stress
645 field. *International Journal of Rock Mechanics and Mining Sciences & Geomechanics Abstracts*,
646 25(3), 171–182. [https://doi.org/10.1016/0148-9062\(88\)92299-1](https://doi.org/10.1016/0148-9062(88)92299-1)

647 Ennis-King, J., LaForce, T., Paterson, L., Dance, T., Jenkins, C., & Cinar, Y. (2017). Interpretation of Above
648 Zone and Storage Zone Pressure Responses to Carbon Dioxide Injection in the 2016 CO2CRC
649 Field Test. *Energy Procedia*, 114, 5671–5679. <https://doi.org/10.1016/j.egypro.2017.03.1706>

650 Espinoza, D. N., & Santamarina, J. C. (2017). CO 2 breakthrough—Caprock sealing efficiency and integrity
651 for carbon geological storage. *International Journal of Greenhouse Gas Control*, 66, 218–229.
652 <https://doi.org/10.1016/j.ijggc.2017.09.019>

653 Faulkner, D. R., Jackson, C. A. L., Lunn, R. J., Schlische, R. W., Shipton, Z. K., Wibberley, C. A. J., &
654 Withjack, M. O. (2010). A review of recent developments concerning the structure, mechanics
655 and fluid flow properties of fault zones. *Journal of Structural Geology*, 32(11), 1557–1575.
656 <https://doi.org/10.1016/j.jsg.2010.06.009>

657 González-Nicolás, A., Baù, D., & Alzraiee, A. (2015). Detection of potential leakage pathways from
658 geological carbon storage by fluid pressure data assimilation. *Advances in Water Resources*,
659 86(PB). <https://doi.org/10.1016/j.advwatres.2015.10.006>

660 Hosseini, S., & Alfi, M. (2016). Time-lapse application of pressure transient analysis for monitoring
661 compressible fluid leakage. *Greenhouse Gases: Science and Technology*, 6(3), 352–369.
662 <https://doi.org/10.1002/ghg.1570>

663 Hosseini, S., Shakiba, M., Sun, A., & Hovorka, S. (2018). In-Zone and Above-Zone Pressure Monitoring
664 Methods for CO2 Geologic Storage. In *Geological Carbon Storage* (pp. 225–241). American
665 Geophysical Union (AGU). <https://doi.org/10.1002/9781119118657.ch11>

666 Hosseini, S. A. (2019). Fault leakage detection and characterization using pressure transient analysis.
667 *Journal of Petroleum Science and Engineering*, 176, 880–886.
668 <https://doi.org/10.1016/j.petrol.2019.01.099>

669 Hovorka, Benson, S. M., Doughty, C., Freifeld, B. M., Sakurai, S., Daley, T. M., et al. (2006). Measuring
670 permanence of CO₂ storage in saline formations: the Frio experiment. *Environmental*
671 *Geosciences*, 13(2), 105–121. <https://doi.org/10.1306/eg.11210505011>

672 Jung, H., Singh, G., Espinoza, D. N., & Wheeler, M. F. (2018). Quantification of a maximum injection
673 volume of CO₂ to avert geomechanical perturbations using a compositional fluid flow reservoir
674 simulator. *Advances in Water Resources*, 112, 160–169.
675 <https://doi.org/10.1016/j.advwatres.2017.12.003>

676 Jung, H., Espinoza, D. N., & Hosseini, S. A. (2020). Wellbore injectivity response to step-rate CO₂
677 injection: Coupled thermo-poro-elastic analysis in a vertically heterogeneous formation.
678 *International Journal of Greenhouse Gas Control*, 102, 103156.
679 <https://doi.org/10.1016/j.ijggc.2020.103156>

680 Jung, Y., Zhou, Q., & Birkholzer, J. T. (2013). Early detection of brine and CO₂ leakage through
681 abandoned wells using pressure and surface-deformation monitoring data: Concept and
682 demonstration. *Advances in Water Resources*, 62, 555–569.
683 <https://doi.org/10.1016/j.advwatres.2013.06.008>

684 Kim, S., & Hosseini, S. A. (2014). Above-zone pressure monitoring and geomechanical analyses for a
685 field-scale CO₂ injection project in Cranfield, MS. *Greenhouse Gases: Science and Technology*,
686 4(1), 81–98. <https://doi.org/10.1002/ghg.1388>

687 Kim, S., & Hosseini, S. A. (2015). Hydro-thermo-mechanical analysis during injection of cold fluid into a
688 geologic formation. *International Journal of Rock Mechanics and Mining Sciences*, 77, 220–236.
689 <https://doi.org/10.1016/j.ijrmms.2015.04.010>

690 Lake, L., Lotfollahi, M., & Bryant, S. L. (2019). CO₂ Enhanced Oil Recovery Experience and its Messages
691 for CO₂ Storage. In *Science of Carbon Storage in Deep Saline Formations* (pp. 11–23). Elsevier.
692 <https://doi.org/10.1016/B978-0-12-812752-0.00002-2>

693 Lake, LW, Johns, R., Rossen, W., & Pope, G. (2014). *Fundamentals of Enhanced Oil Recovery*. Richardson:
694 Society of Petroleum Engineers. Retrieved from [http://store.spe.org/Fundamentals-of-](http://store.spe.org/Fundamentals-of-Enhanced-Oil-Recovery-P921.aspx)
695 [Enhanced-Oil-Recovery-P921.aspx](http://store.spe.org/Fundamentals-of-Enhanced-Oil-Recovery-P921.aspx)

696 Liebscher, A., Möller, F., Bannach, A., Köhler, S., Wiebach, J., Schmidt-Hattenberger, C., et al. (2013).
697 Injection operation and operational pressure–temperature monitoring at the CO₂ storage pilot
698 site Ketzin, Germany—Design, results, recommendations. *International Journal of Greenhouse*
699 *Gas Control*, 15, 163–173. <https://doi.org/10.1016/j.ijggc.2013.02.019>

700 Lindeberg, E. (2011). Modelling pressure and temperature profile in a CO₂ injection well. *Energy*
701 *Procedia*, 4, 3935–3941. <https://doi.org/10.1016/j.egypro.2011.02.332>

702 Meckel, T., Hovorka, S., & Kalyanaraman, N. (2008). Continuous pressure monitoring for large volume
703 CO₂ injections. *Presented at the 9th International Conference on Greenhouse Gas Control*
704 *Technologies (GHGT-9)*.

705 Mishra, S., Oruganti, Y. D., Gupta, N., Ganesh, P. R., McNeil, C., Bhattacharya, I., & Spitznogle, G. (2014).
706 Modeling CO₂ plume migration based on calibration of injection and post-injection pressure
707 response at the AEP Mountaineer Project. *Greenhouse Gases: Science and Technology*, 4(3),
708 331–356. <https://doi.org/10.1002/ghg.1434>

709 Namhata, A., Oladyshkin, S., Dilmore, R. M., Zhang, L., & Nakles, D. V. (2016). Probabilistic Assessment of
710 Above Zone Pressure Predictions at a Geologic Carbon Storage Site. *Scientific Reports*, 6(1),
711 39536. <https://doi.org/10.1038/srep39536>

712 Park, Y.-C., Huh, D.-G., & Park, C.-H. (2012). A pressure-monitoring method to warn CO₂ leakage in
713 geological storage sites. *Environmental Earth Sciences*, 67. [https://doi.org/10.1007/s12665-012-](https://doi.org/10.1007/s12665-012-1667-2)
714 [1667-2](https://doi.org/10.1007/s12665-012-1667-2)

715 Peters, E. J. (2012). *Advanced Petrophysics: Geology, porosity, absolute permeability, heterogeneity, and*
716 *geostatistics*. Greenleaf Book Group.

717 Prevost, J. (2013). *One-Way versus Two-Way Coupling in Reservoir-Geomechanical Models*.
718 *Poromechanics V - Proceedings of the 5th Biot Conference on Poromechanics* (p. 526).
719 <https://doi.org/10.1061/9780784412992.061>

720 Ren, W., Li, G., Tian, S., Sheng, M., Yang, R., & Wang, T. (2016). Comparison of Capillary Pressure-
721 Saturation Models for Gas-Water Systems in Shale Gas Reservoirs. Presented at the SPE Asia
722 Pacific Oil & Gas Conference and Exhibition, OnePetro. <https://doi.org/10.2118/182461-MS>

723 Roussel, N. P., & Agrawal, S. (2017). Introduction to Poroelastic Response Monitoring - Quantifying
724 Hydraulic Fracture Geometry and SRV Permeability from Offset-Well Pressure Data. Presented
725 at the SPE/AAPG/SEG Unconventional Resources Technology Conference, Unconventional
726 Resources Technology Conference. <https://doi.org/10.15530/URTEC-2017-2645414>

727 Rutqvist, Vasco, D. W., & Myer, L. (2009). Coupled reservoir-geomechanical analysis of CO2 injection at
728 In Salah, Algeria. *Energy Procedia*, *1*(1), 1847–1854.
729 <https://doi.org/10.1016/j.egypro.2009.01.241>

730 Rutqvist, J., Vasco, D. W., & Myer, L. (2010). Coupled reservoir-geomechanical analysis of CO2 injection
731 and ground deformations at In Salah, Algeria. *International Journal of Greenhouse Gas Control*,
732 *4*(2), 225–230. <https://doi.org/10.1016/j.ijggc.2009.10.017>

733 Ryu, J., Espinoza, D. N., Balhoff, M. T., & Tavassoli, S. (2019). Simulation of Fault Reactivation Using the
734 HISS Model. Presented at the SPE Annual Technical Conference and Exhibition, OnePetro.
735 <https://doi.org/10.2118/196153-MS>

736 Santos, E. J. P., & Silva, L. B. M. (2022). High-resolution pressure transducer design and associated
737 circuitry to build a network-ready smart sensor for distributed measurement in oil and gas
738 production wells. *Journal of Petroleum Exploration and Production Technology*.
739 <https://doi.org/10.1007/s13202-021-01422-9>

740 Segall, & Fitzgerald. (1998). A note on induced stress changes in hydrocarbon and geothermal reservoirs.
741 *Tectonophysics*, 289(1–3), 117–128. [https://doi.org/10.1016/S0040-1951\(97\)00311-9](https://doi.org/10.1016/S0040-1951(97)00311-9)

742 Singh, G., & Wheeler, M. F. (2016). Compositional flow modeling using a multi-point flux mixed finite
743 element method. *Computational Geosciences*, 20(3), 421–435. [https://doi.org/10.1007/s10596-](https://doi.org/10.1007/s10596-015-9535-2)
744 015-9535-2

745 Sun, W., & Durlofsky, L. (2019). Data-space approaches for uncertainty quantification of CO₂ plume
746 location in geological carbon storage. *Advances in Water Resources*.
747 <https://doi.org/10.1016/J.ADVWATRES.2018.10.028>

748 Tang, M., Ju, X., & Durlofsky, L. J. (2021). Deep-learning-based coupled flow-geomechanics surrogate
749 model for CO₂ sequestration. Retrieved from <https://arxiv.org/abs/2105.01334v1>

750 Tao, Q., Bryant, S. L., Meckel, T., & Luo, Z. (2012). Wellbore Leakage Model for Above-Zone Monitoring
751 at Cranfield, MS. Presented at the Carbon Management Technology Conference, Carbon
752 Management Technology Conference. <https://doi.org/10.7122/151516-MS>

753 Tran, Settari, A., & Nghiem, L. (2004). New Iterative Coupling Between a Reservoir Simulator and a
754 Geomechanics Module. *SPE Journal*, 9(03), 362–369. <https://doi.org/10.2118/88989-PA>

755 Tran, D., Shrivastava, V. K., Nghiem, L. X., & Kohse, B. F. (2009). Geomechanical Risk Mitigation for CO₂
756 Sequestration in Saline Aquifers. Presented at the SPE Annual Technical Conference and
757 Exhibition, OnePetro. <https://doi.org/10.2118/125167-MS>

758 Tsopela, A., Bere, A., Dutko, M., Kato, J., Niranjana, S. C., Jennette, B. G., et al. (2022). CO₂ injection and
759 storage in porous rocks: coupled geomechanical yielding below failure threshold and
760 permeability evolution. *Petroleum Geoscience*, 28(1). <https://doi.org/10.1144/petgeo2020-124>

761 Wiese, B., Zimmer, M., Nowak, M., Pellizzari, L., & Pilz, P. (2013). Well-based hydraulic and geochemical
762 monitoring of the above zone of the CO₂ reservoir at Ketzin, Germany. *Environmental Earth*
763 *Sciences*, 70(8), 3709–3726. <https://doi.org/10.1007/s12665-013-2744-x>

764 Zeidouni, M., & Pooladi-Darvish, M. (2012a). Leakage characterization through above-zone pressure
765 monitoring: 1—Inversion approach. *Journal of Petroleum Science and Engineering*, 98–99, 95–
766 106. <https://doi.org/10.1016/j.petrol.2012.09.006>

767 Zeidouni, M., & Pooladi-Darvish, M. (2012b). Leakage characterization through above-zone pressure
768 monitoring: 2—Design considerations with application to CO2 storage in saline aquifers. *Journal*
769 *of Petroleum Science and Engineering*, 98–99, 69–82.
770 <https://doi.org/10.1016/j.petrol.2012.09.005>

771 Zeidouni, M., & Vilarrasa, V. (2016). Identification of above-zone pressure perturbations caused by
772 leakage from those induced by deformation. *Environmental Earth Sciences*, 75(18), 1271.
773 <https://doi.org/10.1007/s12665-016-6090-7>

774 Zhang, L., Dillmore, R., Namhata, A., & Bromhal, G. (2018). Feasibility of CO2 migration detection using
775 pressure and CO2 saturation monitoring above an imperfect primary seal of a geologic CO2
776 storage formation: a numerical investigation. *Computational Geosciences*, 22(3), 909–923.
777 <https://doi.org/10.1007/s10596-018-9732-x>

778 Zhang, L., Wang, Y., Miao, X., Gan, M., & Li, X. (2019). Geochemistry in geologic CO2 utilization and
779 storage: A brief review. *Advances in Geo-Energy Research*, 3(3), 304–313.

780 Zheng, X., & Espinoza, D. N. (2021a). Measurement of Unloading Pore Volume Compressibility of Frio
781 Sand Under Uniaxial Strain Stress Path and Implications on Reservoir Pressure Management.
782 *Rock Mechanics and Rock Engineering*. <https://doi.org/10.1007/s00603-021-02571-3>

783 Zheng, X., & Espinoza, D. N. (2021b). Multiphase CO2-brine transport properties of synthetic fault gouge.
784 *Marine and Petroleum Geology*, 129, 105054.
785 <https://doi.org/10.1016/j.marpetgeo.2021.105054>

786