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Experimental investigation of plugging and fracturing mechanisms in unconsolidated sand reservoirs under injection of water containing suspended fine particles

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Highlights

- A novel experimental device for radial injection of a suspension in sand specimens is developed.
- Permeability impairment and fracturing of cohesionless sand specimens are explored.
- A low particles concentration in the suspension can induce a significant injectivity loss.
- The fracturing pressure is proportional to the applied confining stress.
- Fracturing of a clogged specimen requires a higher injection pressure than an intact one and leads to a higher permeability recovery.

Abstract

Progressive plugging of the medium due to filter cake formation is considered as a major challenge during Produced Water Re-Injection (PWRI), leading decreased well injectivity during production. Field operations have shown that injectivity can be at least partially restored by fracturing the clogged medium when injecting in the frac-regime. An experimental investigation is performed to explore the effect of the injection of a suspension on the plugging and fracturing processes in an unconsolidated sand formation. The tests are performed by injecting water containing fine particles at a constant low flow rate to first clog a sand specimen (phase 1), then by increasing the flow rate until fracturing (phase 2). Experimental results exhibit a continuous increase of the injection pressure (decrease of injectivity) during phase 1 due to the formation of filter cake build-up caused by the deposition of injected solid particles. During phase 2 when the flow rate is increased, pressure drops are observed and attributed to the formation of fractures, resulting in the increase of the overall permeability of the medium. This is confirmed by post-mortem analysis of the specimens using X-ray Computed Tomography. Small radial fractures (“pseudo-cracks”) induced around the injection point are visible. They appear as localized zones of higher porosity. The effect of the confining pressure and of the suspended particles concentration on the clogging and fracturing of the medium is investigated. It is shown that the clogging process strongly depends on the concentration of particles in the injected fluid. A lower quantity of injected particles is needed to induce the same level of permeability impairment when a lower concentration is used. No significant effect of particle concentration is observed on the fracturing pressure. As with pure water injection, the fracturing pressure is proportional to the imposed confining stress. Moreover, it is observed that the clogged specimen requires a higher injection pressure to reach the frac-regime as compared to an injection scenario with pure water and no filter cake formation and that permeability recovery could be higher.

43 Keywords: Radial injection experiments, Produced Water Re-Injection, Plugging, Fracturing,
44 Unconsolidated sand reservoirs, X-ray Computed Tomography.

45 1. **Introduction**

46 During oil and gas recovery operations, a large volume of liquid waste is also generated from the
47 production wells, of which produced water accounts for the majority, over 80% (Igunnu and Chen,
48 2014). The volume of produced water increases over the lifetime of production. The ratio of produced
49 water to crude oil can be as high as 98% (Farajzadeh, 2004; Veil et al., 2004; Igunnu and Chen, 2014)
50 depending on the nature of the oilfields, the method of drilling the wells, the different types of
51 completion, the age of the production well (Reynolds and Kiker, 2003). Based on the evaluation of
52 various criteria such as cost efficiency, regulatory acceptance, technical feasibility and availability of
53 equipment, etc. Produced Water Re-Injection (PWRI) is well known as the most suitable method for
54 handling produced water (Veil et al., 2004). Before re-injection, produced water is treated to remove
55 organic and inorganic components (heavy metals dispersed oil, suspended solids, chemical
56 compounds, dissolved gases and bacteria, etc.) using combined physical, chemical and biological
57 methods (Ahmadun et al., 2009; Igunnu and Chen, 2014). However, due to treatment costs, current
58 technology and equipment, treated produced water still contains a small amount of impurities such as
59 solid particles of several micrometers in size and oil droplets (Sharma et al., 1997, Mainguy et al.,
60 2020). The re-injection in the matrix regime (i.e., the injection pressure is lower than the horizontal
61 *in-situ* stress) of treated produced water through the injection well into reservoirs leads to the clogging
62 of the medium and consequently, loss of injectivity, due to filtration of these impurities at the reservoir
63 inlet (Sharma et al., 1997; Al-Abduwani et al., 2005; Li and Wong, 2008; Feia et al., 2015). An
64 experimental study conducted by Ochi and Oughanem (2018) showed that the level of plugging
65 damage is mainly controlled by deposition of the suspended particles compared to that contributed
66 by the deposition of oil droplets. Formation damage due to suspended particles has been extensively
67 studied through experiments (Todd et al., 1990; Al-Abduwani et al., 2005; Feia et al., 2015) and
68 modeling approaches (van Oort et al., 1993; Shutong and Sharma, 1997; Al-Abduwani et al., 2005;
69 Zhou et al., 2018). Internal and external cake formations at the entrance of the medium are stated as
70 the dominant mechanisms of formation damage (Shutong and Sharma, 1997; Feia et al., 2015).

71 Some treatments such as clean water injection or chemical additives injection can be performed
72 to partially restore the permeability decline, however, these solutions are relatively expensive and
73 only provide temporary short-term results (Sharma et al., 1997; Souilah et al., 2014; Mainguy et al.,
74 2020). Injection or re-injection of treated produced water in the fracturing regime (i.e., when the
75 injection pressure is higher than the horizontal *in-situ* stress) could be a reasonable solution to
76 overcome formation damage and associated well injectivity (Ochi et al., 2014; Mainguy et al., 2020).
77 Hydraulic fracturing is widely applied in consolidated reservoirs (i.e., rock) and its associated
78 mechanisms are extensively described in the literature (Detournay, 2016). In contrast, fracturing of
79 unconsolidated sand reservoirs is more difficult to achieve and not yet well mastered. Most of the
80 previous studies of hydraulic fracturing in unconsolidated/soft sand formations were mainly related
81 to frac-packing treatment or polymer flooding in which experiments were performed with highly
82 viscous fluids (Bohloli and de Pater, 2006; Dong, 2010; Hurt and Germanovich, 2012) or fluids
83 containing a very high concentration of particles (Golovin et al., 2010; Jasarevic et al., 2010). Very
84 few studies address fracturing in PWRI situations in which the injected fluid has a very low viscosity
85 (around 1 cP) and a low concentration of solid particles and in which the injection is maintained over

86 a long period of time (Onaisi et al., 2011). A literature review on this topic can be found in Nguyen
87 (2022).

88 We emphasize that the subject studied in the present work concerns unconsolidated sand
89 reservoirs for which the fracturing mechanisms are fundamentally different from those involved in
90 fracturing soft rocks. Fracturing of soft rock formations is accompanied by the development of plastic
91 zones at the fracture tip and fluid leak-off in the porous rock. However, the dominant mechanism of
92 fracturing in soft rocks is tensile failure and fracture propagation is controlled by the rock toughness
93 as studied theoretically by Sarris and Papanastasiou (2013), or experimentally in the recent paper of
94 Yan et al. (2022). For unconsolidated sand reservoirs, the possibility of tensile failure is suppressed
95 in favor of shear failure (Bohloli and de Pater, 2006). The formation of what appears as “pseudo-
96 cracks” is the result of shear localization, dilation and fines transport in the granular medium as
97 opposed to tensile fractures obtained during fracking of rock formations (Nguyen et al., 2022).

98 The main objectives of this paper are (1) to experimentally explore the clogging of unconsolidated
99 sand reservoirs due to the injection of water containing suspended particles in the matrix regime and
100 the fracturing response of the clogged specimen upon increasing the flow rate to reach the frac-regime
101 and (2) to investigate the effect of confining pressure and particle concentration on the clogging
102 damage and on the fracturing response of sand specimens. Finally, a comparison of the results
103 obtained in this work with those under pure water injection presented in Nguyen et al. (2022) is
104 proposed.

105 **2. Experimental setup and tested materials**

106 To mimic the PWRI operations in unconsolidated sand reservoirs, a radial injection device has
107 been developed (Fig. 1). Details on this experimental device can be found in Nguyen et al. (2022).
108 This setup permits a radial injection of a fluid with or without suspended particles into a cohesionless
109 dense sand specimen of 100 mm diameter and 200 mm height under controlled constant flow rate.
110 The specimen is prepared at a controlled density in order to obtain a permeability similar to that of
111 *in-situ* reservoirs (about 1 Darcy).

112 The injection cell contains a central tube, fixed on the lower baseplate, which permits to perform
113 a radial injection through a cylindrical specimen under imposed axial stress and confining pressure.
114 The cell is fabricated with a limited number of metallic pieces (Fig. 2), providing a possibility to
115 observe the granular structure of the specimen using X-ray Computed Tomography. Therefore, it is
116 possible to visualize the entire specimen structure before and after the experiments with a very high
117 scanning resolution. This is an important advantage of this device as compared to other setups
118 described in the literature (Nguyen, 2022).

119 Fontainebleau silica sand NE34 (composed 99% of silica with $D_{50} = 210 \mu\text{m}$) and two different
120 silica particles (C10 with $D_{50} = 20 \mu\text{m}$ and C500 with $D_{50} = 4.5 \mu\text{m}$) were selected to perform the
121 experimental program. The physical characteristics of these materials are presented in Table 1. The
122 specimen is prepared with a mixture of NE34 sand and 10% of C10 particles in order to represent an
123 initially damaged zone due to PWRI whereas smaller fines C500 are selected as the suspended
124 particles carried in the injection fluid. By adjusting the amount of C10 particles, we can obtain various
125 states of initial permeability of the specimen. The average C500 particle size ($4.5 \mu\text{m}$) in the injected
126 fluid is within the range of that in reinjected produced water (1 to several tenths of μm as mentioned
127 in Mainguy et al., 2020). Since the C10 and C500 particles are composed of silica, we avoid any
128 chemical interaction with the NE34 sand. Similar compositions of the tested specimens and of the

129 injection fluid have been used in previous studies (Feia et al., 2015; Nguyen et al., 2022). The particle
130 size distribution of these materials is established by laser diffraction granulometry (Fig. 3). The data
131 given by the manufacturer allows to assess the accuracy of the measurement using this technique.
132 The grain size distribution curves of different mixtures of NE34 + 10% C10 are also presented in Fig.
133 3, showing the good homogeneity and mixing repeatability of these materials (see also Nguyen et al.,
134 2022).

135 3. Test procedure and specimen preparation

136 The complete testing procedure consists of the following steps:

- 137 - Fabrication of the specimen
- 138 - Saturation and application of the stress conditions
- 139 - Injection of water containing suspended particles at a low constant flow rate to plug the
140 specimen and subsequent increase of the flow rate by steps until fracturing
- 141 - Injection of a small volume of dye to visualize the flow pattern after fracturing
- 142 - Scan of the specimen post-mortem using X-ray Computed Tomography
- 143 - Manual horizontal excavation of the specimen and visual observation of the fractures

144 Details on specimen preparation, saturation can be found in Nguyen et al. (2022).

145 The reconstituted specimen consists of a central injection zone and of two low permeability layers
146 on its lower and upper parts. Two small membranes are placed between these layers in order to
147 prevent the vertical flow out of the injection zone. Due to the presence of fine particles in the mixture
148 and a very dense state of the N34 sand matrix ($I_{D\ NE34} = 0.9$), manual compaction in 10 layers of 2 cm
149 using a specific compaction groomer is applied to prepare the specimen. The surface of each
150 compacted layer is well scarified before filling the next one to avoid segregation. The injection zone
151 contains 10% (by mass) of C10 particles whereas the lower permeability layers contain 32% of C10
152 particles. The characteristics of the reference specimen are presented in Table 2. The upper and lower
153 layers of low permeability are compacted at a lower density index of the sand matrix ($I_{D\ NE34} = 0.6$)
154 because of the high concentration of C10 particles (32%) in order to avoid the risk of breaking the
155 injection tube made by PMMA material. Too strong compaction of the upper low permeability layer
156 may also influence the density of the injection zone below. Once the specimen is fabricated, it is
157 saturated with de-aired water. The desired stress conditions are applied under drained conditions
158 before starting the injection process. The confining pressure is applied using an air-water
159 pressurization cell and the axial stress is applied by the Press TRI-SCAN (Fig. 1). In drained
160 conditions, the initial pore pressure is zero and no excess pore pressure is generated inside the
161 specimen during the application of the initial confining and axial stresses (the sand specimen has a
162 high permeability so that during the consolidation phase, the pore pressure does not increase).
163 Following the observations of Benahmed (2001), the high density index of the specimen guarantees
164 that in the range of stresses applied in the tests, the application of the confining pressure and of the
165 axial stress does not affect the void ratio of the sample, and thus the initial permeability. During the
166 injection test, the imposed stresses are kept constant.

167 The various phases of the injection process are illustrated in Fig. 4. The experiment is performed
168 under controlled flow rate. The plugging process is simulated by first radially injecting water
169 containing suspended particles at a constant flow rate in the matrix regime to partially clog the sand
170 specimen (Fig. 4b), then the flow rate is increased rapidly in order to fracture this damaged specimen
171 and to (partially)retrieve the loss of injectivity (Fig. 4c). r_0 , r_c , r_l are defined as the radius of the

172 injection tube, internal cake and specimen, respectively. The suspension is prepared in a 20l water
173 tank (Fig. 1) using an efficient mixer to ensure the homogeneity of suspension in water. Fig. 5 presents
174 a schematic diagram of the injection program with the two injection phases: plugging and fracturing.
175 The final state of the plugging phase (phase 1) is chosen to provide a reference permeability of 80
176 mD before starting the fracturing phase. This permits a comparison of the critical fracturing pressure
177 P_{frac} with that obtained in the tests with pure water injection in a specimen containing 22% of C10
178 particles as described in the study by Nguyen et al. (2022). Nevertheless, it is expected that the internal
179 structure of the resulting partially clogged specimen is different from that of a homogeneous specimen
180 prepared with 22% of C10 particles. During the fracturing phase (phase 2), the flow rate is increased
181 by steps of 0.2 l/min (1.5 minutes for each step) until reaching the initiation of the frac-regime which
182 is defined as first sharp pressure drop recorded at the inlet pressure transducer. Four injection steps
183 (10 minutes for each step) are carried out in the frac-regime with the same increase of the flow rate
184 of 0.033 l/min as the tests performed by Nguyen et al. (2022) in order to compare the increase of the
185 permeability obtained in different injection scenarios. The injection steps in the frac-regime last
186 longer than those in the matrix regime to track the evolution of the injection pressure after a sudden
187 drop. At the end of the injection, a bleu dye (Basacid® Blue 762) is injected through the central tube
188 to visualize the flow pattern within the specimen after fracturing.

189 4. Typical experimental results

190 4.1 Pore pressure evolution

191 Fig. 6a presents the evolution of the pore pressure for the SP1 test. For this test, the imposed
192 confining pressure and axial stress are 200 kPa and 400 kPa respectively (Table 3). This corresponds
193 to a stress ratio K_0 of 0.5 and can represent the conditions of a reservoir at shallow depth. Pure water
194 was initially injected at a rate of 0.2 l/min to measure the initial permeability of the specimen (Fig.
195 6b). The measured pressure P_I stabilized quickly at a value of 13 kPa, corresponding to an initial
196 permeability of 670 mD. The suspension was injected in two phases: plugging (phase 1) and
197 fracturing (phase 2). The first one was performed at a constant flow rate of 0.2 l/min for about 6 hours
198 until the injection fracture reached 100 kPa (Fig. 6c), corresponding to a value of the overall
199 permeability of 80 mD which is 7.7 times smaller than the initial value. This indicates the formation
200 of an internal cake at the entrance of the medium. This reference value of the overall permeability
201 was chosen for easier comparison of the critical fracturing pressure of the various tests which will be
202 detailed later in this paper.

203 Fig. 6d presents the change in pore pressure during phase 2. During the matrix injection regime,
204 the flow rate was increased in steps of 0.2 l/min. Each step was maintained for approximately 1.5
205 min. A continuous increase in pressure was observed during these steps (see Fig. 6e) which is
206 attributed to two phenomena: mobilization of C10 particles present in the mixture and further
207 deposition of suspended particles in the filter cake formed during the clogging phase (see also Nguyen
208 et al., 2022). According to Lafleur et al. (1989) the grain size distribution of the specimen containing
209 10% C10 (Fig. 3) is classified as the upwardly concave distribution or internally unstable distribution
210 which is susceptible to internal erosion of fine particles in the pore network (Marot and Benamar,
211 2012). During injection, a small fraction of fine particles was detached and transported within the
212 sand matrix and subsequently captured at the pore throats which results in a local clogging of the
213 medium, and consequently, a decrease in overall permeability. This phenomenon has been widely

214 investigated in the literature (Skempton and Brogan, 1994; Tomlinson and Vaid, 2000; Bendahmane
215 et al., 2008; Marot and Benamar, 2012; Chang and Zhang, 2013).

216 The fracturing state (i.e., the first pressure drop) was identified at a flow rate Q_{frac} of 2.23 l/min.
217 Beyond this point, a pronounce drop of the injection pressure was observed, exhibiting a gain of the
218 overall permeability during fracturing. Injection was carried out in the frac-regime with three more
219 steps of 10 minutes each corresponding to a flow rate of 2.26, 2.29 and 2.33 l/min respectively then
220 the flow rate was decreased to zero. Fig. 7a presents the evolution of the injection pressure versus the
221 flow rate during the test. At a constant flow rate of 0.2 l/min, we observe a progressive increase of
222 the pressure up to 100 kPa (plugging phase). Then, when increasing the flow rate, a quasi-proportional
223 increase of the injection pressure is observed. Note that once the filter cake starts forming within the
224 specimen, the flow pattern is not symmetrical along the injection tube anymore because of the
225 heterogeneity of the sand pack due to deposited particles. Thus, using Darcy's law, the evaluation of
226 the permeability from the relationship between the flow rate and the injection pressure only gives an
227 overall equivalent permeability of the system. For this test, fracturing occurs at a critical fracturing
228 pressure P_{frac} is 706 kPa, corresponding to 3.53 times the confining pressure. In the fracturing regime,
229 a sharp decline of the slope of the pressure – flow rate curve is identified. When decreasing the flow
230 rate to zero, a lower slope of pressure – flow rate curve indicates the increase in overall permeability
231 after fracturing. Fig. 7b presents the results in terms of the apparent permeability – flow rate curve.
232 During phase 1 at a flow rate of 0.2 l/min, the permeability decreases from 670 mD to 80 mD at the
233 end of plugging phase. A significant increase of the permeability is observed when reaching the
234 fracturing regime at a critical flow rate of 2.23 l/min.

235 To estimate the gain in permeability, denoted by g , the average values of the permeability
236 between the matrix regime of phase 2, $k_{av,mat}$ and at the end of the test, $k_{av,unload}$ (when the flow rate is
237 decreased) are compared based on the linear fit of the pressure – flow rate curve:

$$g = (k_{av,unload} / k_{av,mat} - 1) \times 100 (\%) \quad (1)$$

238 For the SP1test, fracturing of the medium permits a gain of 41% of the overall permeability.
239 However, the recovery is smaller than the permeability loss during the plugging phase. Note that the
240 injection time and the flow rate play an important role in the change of permeability during this
241 experiment (Nguyen et al., 2022).

242 Fig. 8 presents the results in terms of the mass of injected particles. About 0.75g of C500 injected
243 during the plugging phase leads to a loss of 87% of the permeability. During the frac-regime, more
244 suspended particles (about 0.9g) were injected than during the plugging phase. However, these
245 particles did not cause a decrease of the permeability. This is mainly because of the high flow rate
246 and of the occurrence of fractures, allowing the particles to penetrate into the medium without any
247 further deposition on the filter cake. This observation confirms the effectiveness of produced water
248 injection in the fracturing regime, even though a filter cake has been formed at the wellbore.

249 4.2 Disassembling phase

250 At the end of the injection phase, a small volume of a mixture of water and 0.2% blue Basacid
251 was injected to visualize the flow pattern within the specimen. Before excavating, the specimen was
252 scanned using X-ray CT. Fig. 9 shows some selected X-ray images at different heights of the
253 specimen, two vertical fractures are detected near the injection tube in the upper part of the specimen
254 (from $H = 3$ to $H = 12$ cm). These fractures are short and tortuous. To obtain a 3D view of the fractures,
255 image processing was applied to the scans following three steps: filtering (reduction of the noise of

256 X-ray images), thresholding (segmentation of the fractures and the surrounding medium), volume
257 rendering (construction of a 3D image). This process was performed using FIJI open-source software
258 (Schindelin et al., 2012). The 3D views of two typical sections containing fractures are shown in Fig.
259 10. For specimen SP1, it is observed that the fractured zone is situated in the upper part. In order to
260 obtain a good resolution of the images, we have chosen two zones (4 to 6 cm and 6 to 8 cm) with a
261 height of 2 cm each in the central part of the specimen. From the different views of these fractures,
262 we see that they are quite curvy in both vertical and horizontal direction.

263 Fig. 11 shows some views of the specimen when removing the drainage system and the external
264 latex membrane. From the outer view (Fig. 11a), the invasion of the injected blue dye is observed
265 only in the upper part which indicates that a higher flow occurs in this area and the fractures observed
266 during excavation coincide with those detected in the images of the X-Ray scanned specimen (Fig.
267 11). Nguyen et al. (2022) have identified the fracturing mechanisms as the coupled phenomena of the
268 formation of dilatant shear bands in the sand matrix and the subsequent transport of small particles
269 present in these bands to form the fractures (i.e., pseudo cracks of high porosity) induced around the
270 injection tube.

271 **5. Sensitivity analysis**

272 Six tests have been performed to study the effect of suspended particle concentration and of
273 confining pressure on the formation damage by deposited particles as well as the fracturing response
274 of sand specimens (Table 3). Then, a comparison of the results obtained with suspended particles
275 injection with those performed under pure water injection by Nguyen et al. (2022) is proposed in
276 order to explore the effect of the filter cake build-up at the sand surface on the fracturing of the
277 medium.

278 *5.1 Test repeatability*

279 For every new experimental protocol, it is important to evaluate the repeatability of the test. A
280 test called SP2 has been performed under the same testing conditions as the reference test (SP1). Fig.
281 12a,b shows a comparison of these tests during the plugging phase in terms of pressure and apparent
282 permeability evolution. This phase was carried out at $q = 0.2$ l/min. A slight difference of the initial
283 permeability was observed, depending on the initial structure of the NE34 sand and C10 particles
284 mixture. The SP1 test showed a relatively faster increase in inlet injection pressure, corresponding to
285 a faster decrease in overall permeability mainly due to the complexity of particle deposition, transport
286 and rearrangement during injection.

287 As for the reference test, the flow rate was gradually increased in steps of 0.2 l/min until fracturing
288 occurs. A fairly good repeatability in terms of pressure – flow rate curve is observed (Fig. 12c). In
289 these tests, fracturing initiates when the injection pressure reaches about 3.5 times the confining
290 pressure (Fig. 12d). During the further fracturing steps, test SP1 shows a stronger drop of the injection
291 pressure as compared to SP2, which indicates a slightly higher increase of the overall permeability
292 after fracturing (a gain of 41% for SP1 as compared to 22.5% for SP2).

293 *5.2 Effect of the concentration of particles in the injection fluid*

294 In this part, we first evaluate the impact of suspended particles concentration on the clogging of
295 the medium and the effect of this parameter on the fracturing process is then discussed.

296 5.2.1 *Plugging of the medium*

297 Five tests (SP1, SP2, SP3, SP5 and SP6) were conducted under the same testing conditions with
298 only the concentration of suspended particles in the injected fluid changed (10, 20 and 50 mg/l). These
299 specimens contained a mixture of NE34 sand and 10% of C10 particles, compacted at a density index
300 of the sand matrix $I_{D\ NE34}$ of 0.9. The stress conditions are 200 kPa confining pressure and 400 kPa
301 axial stress. The injection was maintained constant at 0.2 l/min until the injection pressure reached a
302 target value of 100 kPa. The results in terms of injection pressure versus injected particles mass are
303 shown in Fig. 13a. We observe that the increase of the injection pressure is more pronounced (in
304 terms of the quantity of injected particles) with a lower concentration of suspended particles. Similar
305 results have been obtained by Feia et al. (2015) when investigating the effect of particles
306 concentration on permeability impairment of a sand specimen under axial injection flow. On the
307 contrary, when plotting the results in terms of pressure versus injected volume, it is observed that a
308 higher concentration results in a faster increase of the injection pressure, and consequently, a faster
309 plugging rate. Similar results were also obtained by Ochi and Oughanem (2018). Following Feia et
310 al. (2015), this could be explained by the fact that, at a relatively low injection rate, when injecting at
311 a lower particles concentration, the particles have time to settle on the sand grains with little re-
312 entrainment, thus less deposited particles are needed to plug the medium. However, because of the
313 lower concentration, a larger volume of the injected fluid is needed to provide enough deposited
314 particles.

315 Test SP5 was performed with only the plugging phase in order to visualize the profile of deposited
316 particles at the interface between specimen and injection tube (i.e., at the inlet of the medium). At the
317 end of this test, a typical sample was carefully taken in a zone close to the injection tube and was
318 observed using an optical microscope. As shown in Fig. 14, injected particles are captured in the
319 porous medium to form the internal cake, consequently, reducing the overall permeability of the
320 specimen. At this state, the external cake has not been formed yet. The results obtained validate the
321 scenario of the cake formation before carrying out the fracturing phase in which only a filter cake is
322 formed without the plugging of the injection tube.

323 5.2.2 *Fracturing of the medium*

324 Changing the particles concentration affects the formation of the filter cake during the plugging
325 phase. Therefore, it may give different structures of the clogging zone, especially, around the injection
326 point. To investigate the effect of this parameter on the fracturing process, three different
327 concentrations have been tested (10, 20 and 50 mg/l). However, test SP6 with 50 mg/l of particles did
328 not generate fractures because of the plugging of the injection tube due to the deposition of injected
329 particles in the helical groove of the tube as observed during the disassembling. Therefore, we
330 compare the results obtained in the tests with the concentration of 10 and 20 mg/l (Fig. 15). It can be
331 observed that the particles concentration, within the range tested, has no significant effect on the
332 critical fracturing pressure. Fracturing occurred when the injection pressure reached about 3.45 to
333 3.65 times the confining pressure. Due to a sudden failure of the pump at the end of injection, test
334 SP3 (20 mg/l) was performed with only three flow rate steps in the frac-regime (instead of four steps)
335 (Fig. 16a), thus the increase of the apparent permeability is smaller than for the two other tests with
336 10 mg/l. In test SP3 (20 mg/l), fractures were generated only in the upper part of the injection zone
337 from $H = 2$ cm to $H = 8$ cm which is shorter than for reference test SP1. This can explain the smallest
338 increase of the overall permeability after fracturing in test SP3. Similar fracture morphology is
339 observed in tests SP1 and SP3 (Fig. 10 and Fig. 16b).

340 5.3 *Effect of the confining pressure on the fracturing process.*

341 The experimental results with pure water injection performed by Nguyen et al. (2022) showed
342 that the confining pressure is the primary factor controlling the fracturing pressure. It is thus
343 interesting to investigate the effect of this parameter when injecting water with suspended particles.
344 To do so, test SP4 was carried out at a lower confining pressure (120 kPa) as compared to the
345 reference test (200 kPa) while keeping the same stress ratio K_0 of 0.5. The comparison is shown in
346 Fig. 17. The higher the confining pressure, the higher the fracturing pressure and the lower the
347 increase in permeability. Interestingly, fracturing occurs when the injection pressure reaches about
348 3.5 times the confining pressure for both tests. A sudden drop of the injection pressure from P_{frac} of
349 420 kPa to 180 kPa is observed at the critical fracturing state.

350 The observation of the fractures after the test is consistent with the above results. As shown in
351 Fig. 18, a larger and more complex network of fractures is observed in specimen SP4 as compared to
352 specimen SP1 under 200 kPa of σ_h (Fig. 10) and can be related to the strong drop of the injection
353 pressure observed when reaching the fracturing state. During the SP1, fractures were only generated
354 in the upper part of the specimen whereas fractures propagated all along the injection tube during test
355 SP4. This observation is in accordance with the first noticeable fracturing point and a higher gain of
356 the apparent permeability in test SP4 (200% of the permeability gain g for test SP4 as compared to
357 41% for SP1).

358 Nevertheless, the observation of the samples made after the experiments gives only the final state
359 and future investigations in which scanning of the specimens could be performed during injection are
360 needed to precisely identify the onset and propagation/coalescence of the fractures. This however,
361 requires significant modifications of the experimental device.

362 5.4 *Effect of the internal cake formation on the fracturing response of the medium*

363 Nguyen et al. (2022) have explored fracturing mechanisms, under pure water injection, in the
364 medium containing a homogeneous mixture of sand and fine particles which represents the final state
365 of an internal cake induced by PWRI. In this scenario, the testing conditions can be well controlled
366 and a homogeneous specimen allows to avoid unexpected or preferential flows within the sand
367 specimen. The results presented in this work, on the other hand, get closer to the phenomena that
368 occur during PWRI operations in practice with the combined phenomena: formation damage due to
369 the formation of a filter cake on the sand surface in the matrix regime and then fracturing of the
370 medium. However, the physical processes associated with the second scenario are more complex with
371 the superposition and competition of several processes such as filtration, deposition, detachment,
372 transport of fine particles and formation of dilatant deformation bands in the sand matrix.

373 In this part, we present a comparison of the results obtained for the two injection scenarios
374 performed in the radial injection cell. Two test series with two different magnitudes of confining
375 pressure (120 kPa and 200 kPa) are evaluated. The obtained results show that the injection tests with
376 suspended particles need a higher pressure to reach the frac-regime (Fig. 19a,c). The ratio between
377 the fracturing pressure and the confining pressure is about 3.5 for the injection of suspended particles
378 and only 2.5 for pure water (Fig. 19b,d). With the same number of steps in the frac-regime, the
379 suspended particles injection tests exhibit a higher recovery of permeability. This result is confirmed
380 by the appearance of longer fractures around the injection tube as shown Fig. 20. The fracture pattern
381 inside the clogged specimen (Scenario 2) is much more complex. Instead of propagating radially in

382 the flow direction from the injection tube, the fractures extend in different branches as observed in
383 the specimen SP4.

384 Indeed, in Scenario 2, the fracture distribution is heterogeneous along the specimen height. Note
385 that in the case of injection of pure water (see Nguyen et al., 2022), the fracture pattern mostly
386 develops in the central part of the specimen. Here, when injecting a suspension, the fracture pattern
387 is much more complex and depends upon the heterogeneity of the deposition of small particles along
388 the height during the clogging process. Although it is observed in tests SP1 and SP3 that fractures are
389 situated in the upper part of the sample, for SP4 they are located in the central part. No clear
390 explanation can be drawn for the moment and further exploration of the changes induced in the
391 granular structure of the specimen by the clogging would be needed. Interestingly, for both injection
392 scenarios, the value of the normalized fracturing pressure (P_{frac}/σ_h) is not affected by the change of
393 the confining pressure within the range tested here (Fig. 21).

394 To better understand the difference of the critical fracturing pressure, it is interesting to analyze
395 the effect of the filter cake on the critical pressure required for fracturing. Similarly to our results,
396 other works (Farajzadeh, 2004; Wong and Mettananda, 2010; Feia et al., 2015; Ochi and Oughanem,
397 2018) have shown that, during the plugging process, only the deposition of particles at the first layer
398 (filter cake) affects the overall permeability decline of the specimen (equivalent to the increase of the
399 inlet pressure measured at the entrance of the specimen) whereas the pressures measured at different
400 positions within the specimen do not exhibit any significant change as illustrated in Fig. 22. ΔP_{total}
401 and ΔP_c represent the total pressure loss and the pressure loss inside the internal cake, respectively.
402 The presence of this cake may require a higher injection pressure to firstly break or destabilize this
403 zone before creating fractures within the specimen. Besides the occurrence of fracturing of the
404 specimen, the breakage or unclogging of the filter cake also plays an important role on the increase
405 of the permeability in the frac-regime. This could explain why, after fracturing, a higher gain of the
406 permeability can be obtained for the tests with injection of suspended particles.

407 **6. Conclusions**

408 In this work, an experimental study has been performed in a newly designed radial injection cell,
409 aiming to mimic the process of re-injection of produced water in sand reservoirs in both matrix and
410 frac-regimes.

411 Injection of suspended particles in the matrix regime results in a decrease in overall permeability
412 due to the formation of an internal and/or external cake within the soil surrounding the injection tube.
413 It is shown that when injecting at a lower particles concentration (10 mg/l), a smaller amount of
414 injected particles (but a higher injected fluid volume) is needed to induce the same level of plugging
415 in terms of pressure increase as compared to injecting with a higher particles concentration in the
416 fluid (20 and 50 mg/l).

417 Injecting in the frac-regime, on the other hand, allows to partially restore the injectivity by
418 breakage of the filter cake and subsequent fracturing of the medium. Moreover, in the frac-regime, it
419 is possible to continue to inject the suspension without further deterioration of the overall
420 permeability. An increase of the confining pressure (from 120 kPa to 200 kPa) leads to a proportional
421 increase of the critical fracturing pressure. For the range of particles concentration studied (10 and 20
422 mg/l), no clear effect of this parameter was observed on both the fracturing pressure and the fracture
423 geometry. In all the tests, fracturing occurred when the injection pressure reached about 3.5 times the
424 confining pressure.

425 It is interesting to compare the results of two injection scenarios: injection of pure water as
426 performed by Nguyen et al. (2022) and injection of water with suspended particles. The second
427 scenario exhibits a higher normalized fracturing pressure (P_{frac}/σ_h). In the frac regime, a higher gain
428 of the permeability can be obtained and longer fractures are observed. These observations highlight
429 the effect of the filter cake: The fracturing process involves both the breakage of the cake and the
430 formation of fractures inside the specimen. In both injection scenarios, a higher confining pressure
431 leads to a higher critical fracturing pressure, a lower increase of overall permeability as well as shorter
432 fractures induced within the specimen.

433 This experimental work will be extended in the future by performing the injection tests in a large
434 injection device to better simulate reservoir conditions and to explore the size effect on the fracturing
435 conditions.

436

437 **Declaration of competing interest**

438 The authors declare no competing financial interest.

439

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444

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548 **List of Symbols**

549

Symbol	Units	Definition
$I_{D\ NE34}$		Density index of the NE34 sand matrix
k	Darcy	Intrinsic permeability
$k_{av,mat}$	Darcy	Average permeability of specimen during the matrix regime
$k_{av,unload}$	Darcy	Average permeability of specimen during the unloading phase
K_0		Stress ratio coefficient
g	%	Gain of the permeability after fracturing
p	kPa	Pressure
P_1	kPa	Measured pressure by the inlet pressure transducer
P_2	kPa	Measured pressure by the outlet pressure transducer
P_{frac}	kPa	First drop pressure observed during fracturing regime
P_{in}	kPa	Pressure at the entrance of injection tube
q	l/min	Flow rate
Q_{frac}	l/min	Flow rate corresponding to the first drop pressure
t	min	Time
σ_h	kPa	Confining pressure
σ_v	kPa	Axial stress

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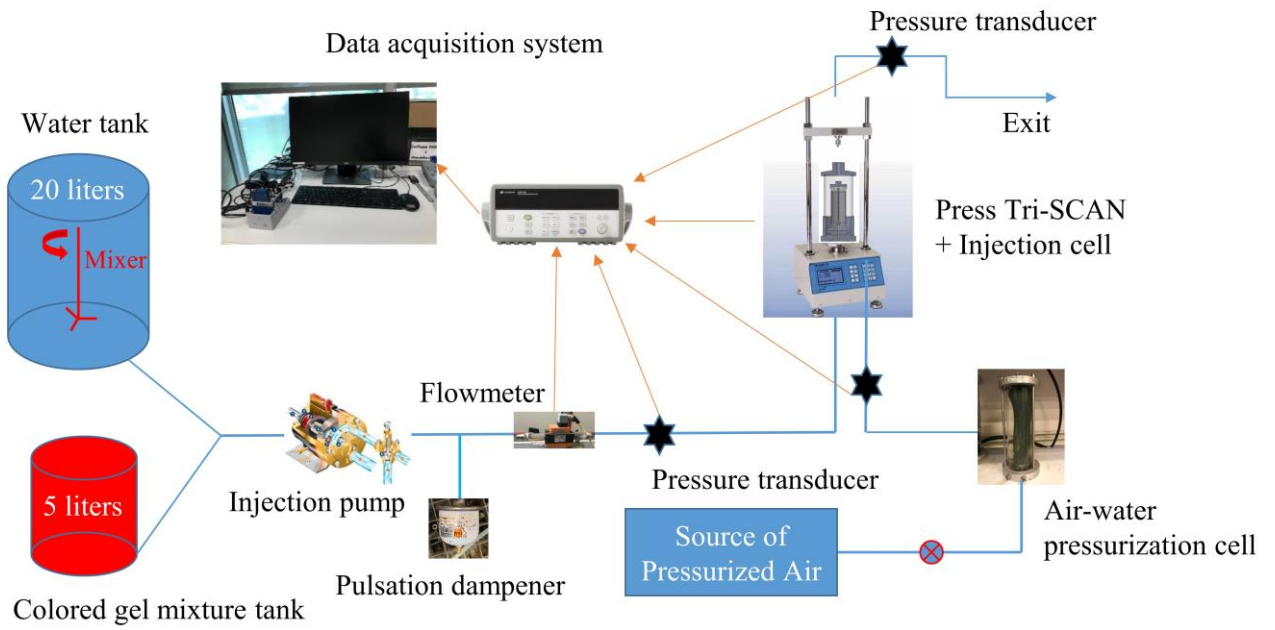
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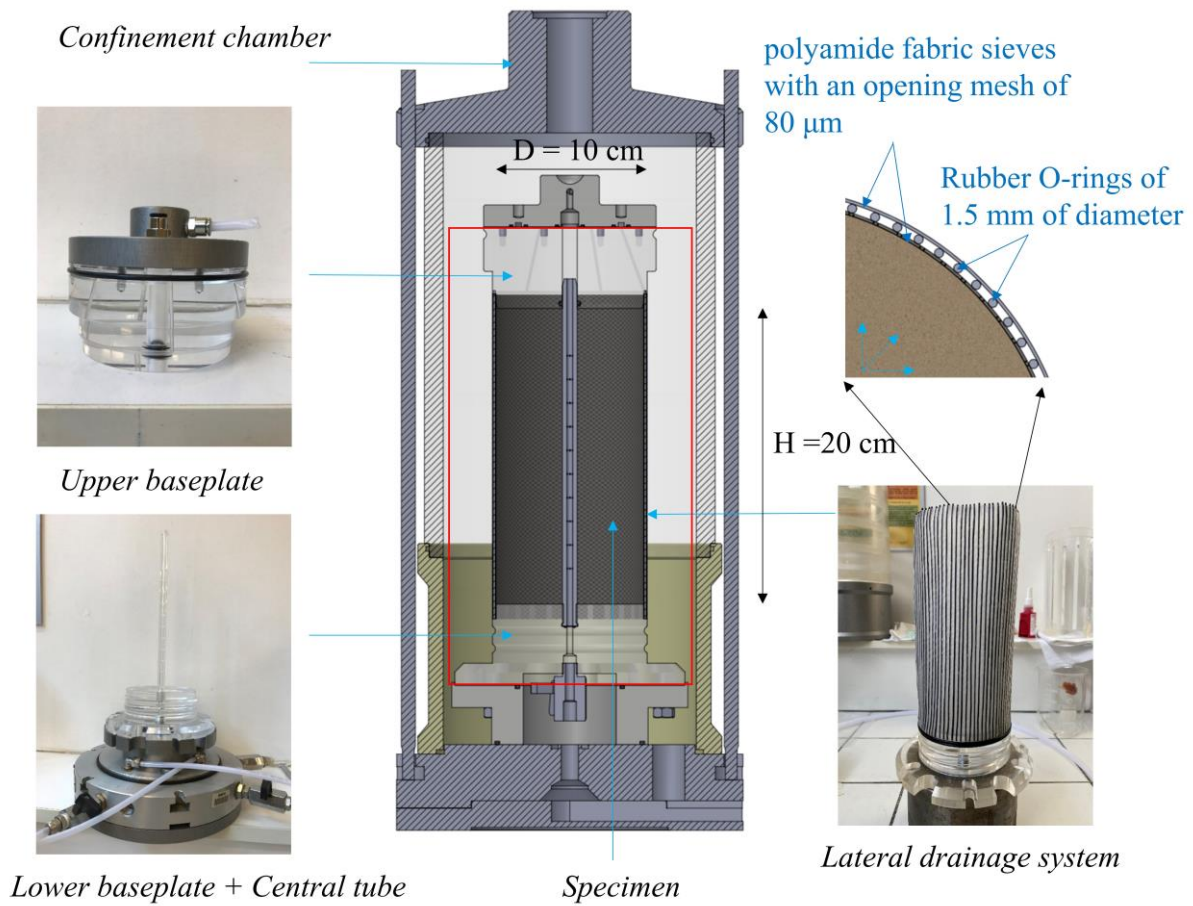
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557 Fig. 1: Functional scheme of the radial injection cell setup (after Nguyen et al., 2022).

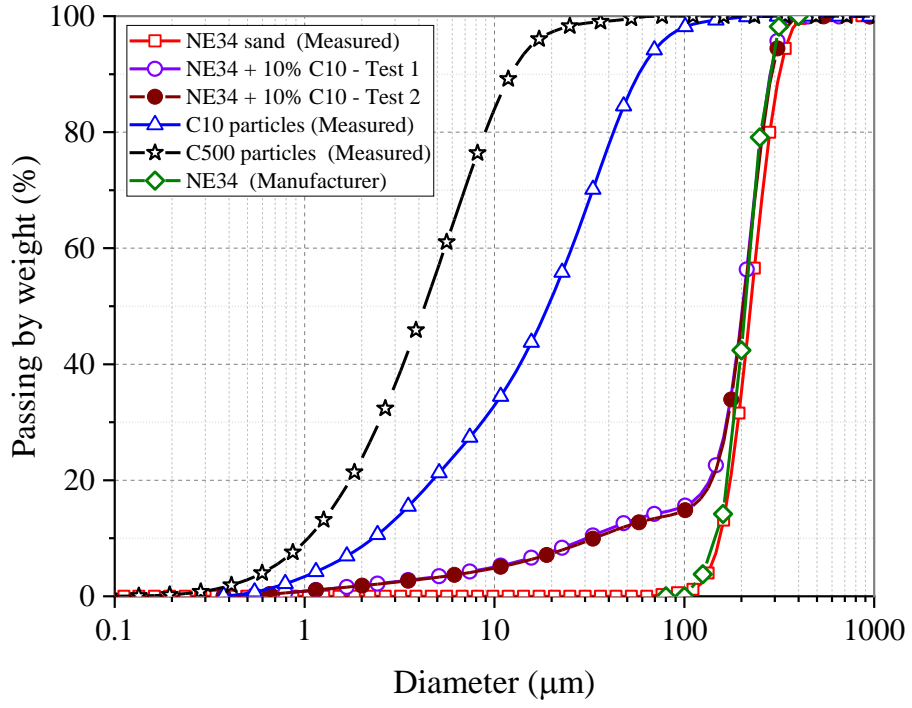
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560 Fig. 2: 2D cross section of the radial injection cell and its corresponding components (from Nguyen
561 et al., 2022).

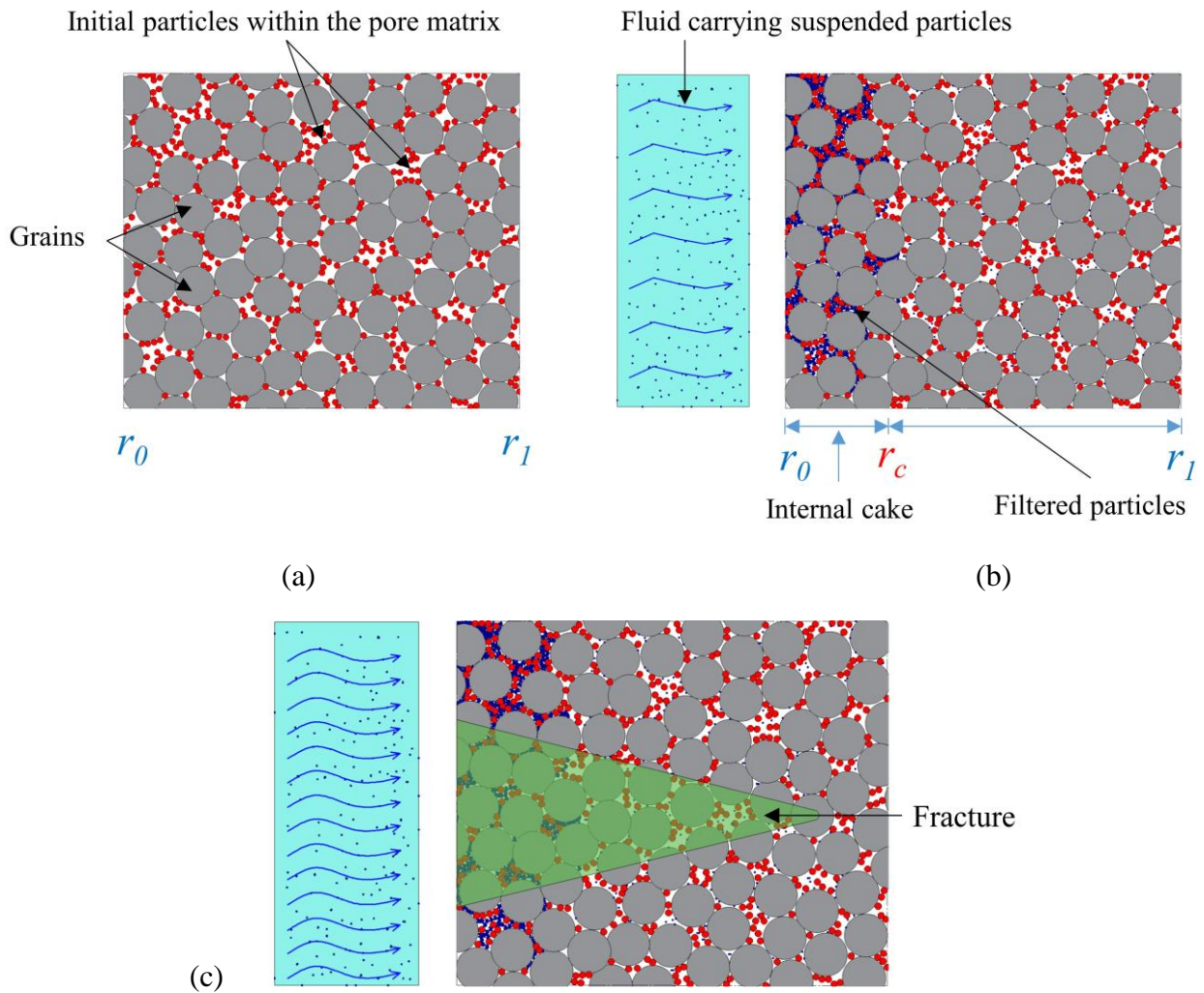
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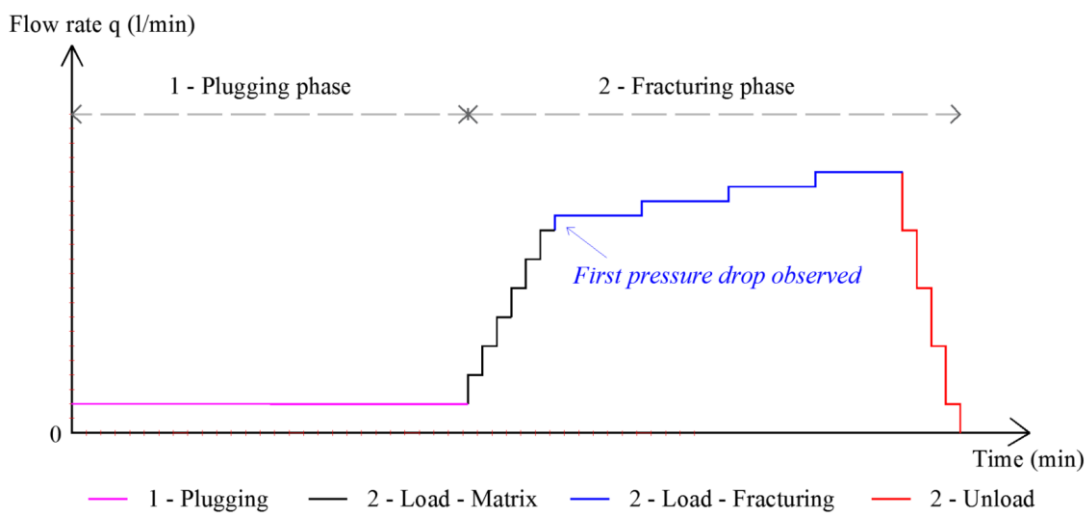
Fig. 3: Grain size distribution of the tested materials.



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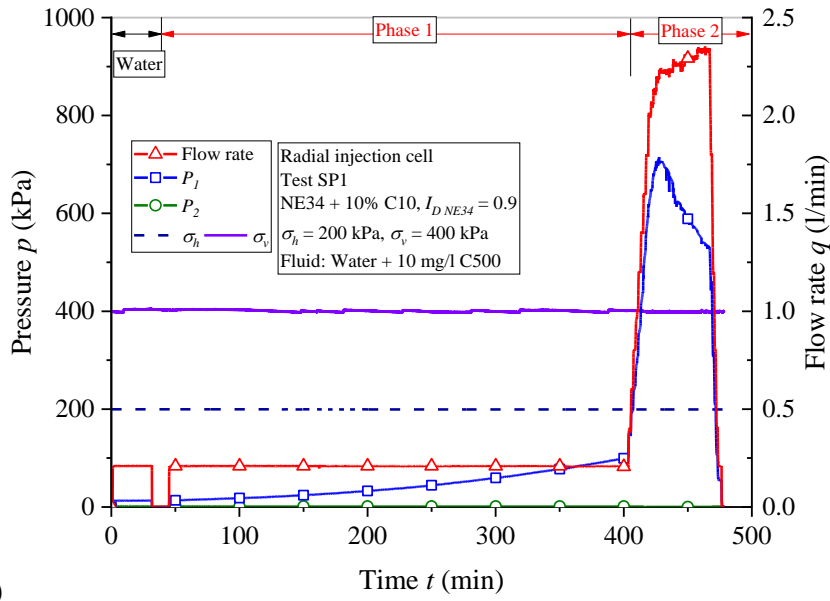
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567 Fig. 4: Various phases of the injection process: (a) initial state of the specimen; (b) plugging of the
 568 medium due to the deposition of suspended particles; (c) fracturing of the clogged specimen under
 569 high injection pressure.



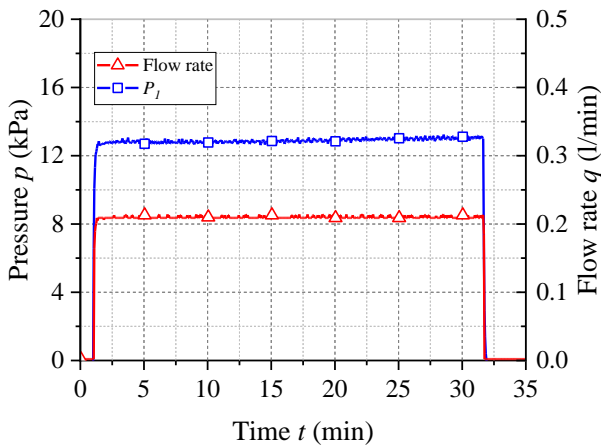
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571 Fig. 5: Scheme of the injection program with two injection phases: plugging and fracturing



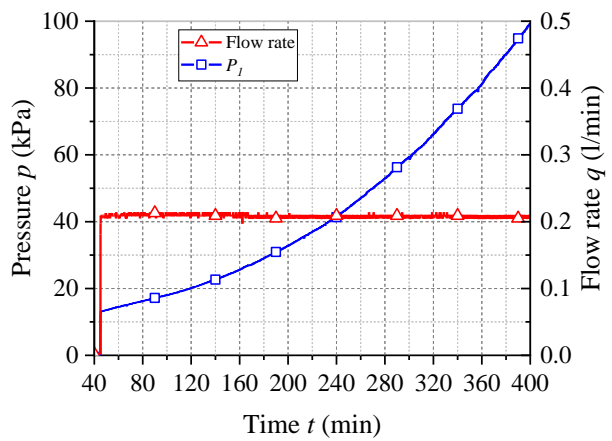
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(a)

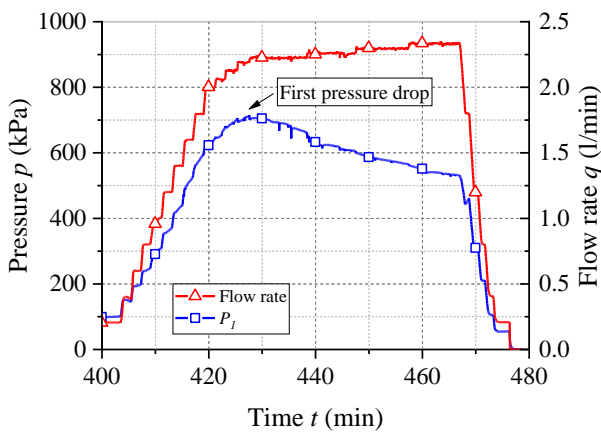


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(b)

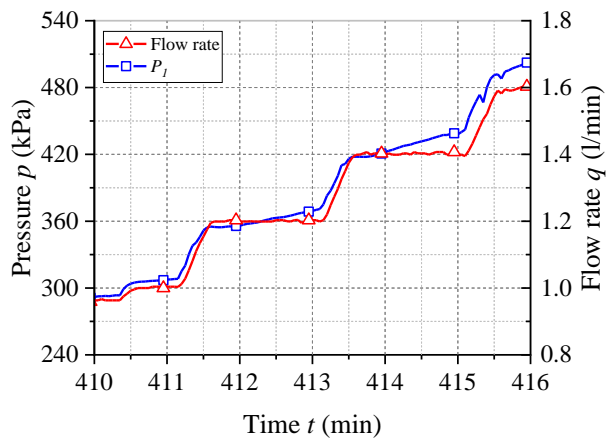


(c)



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(d)



(e)

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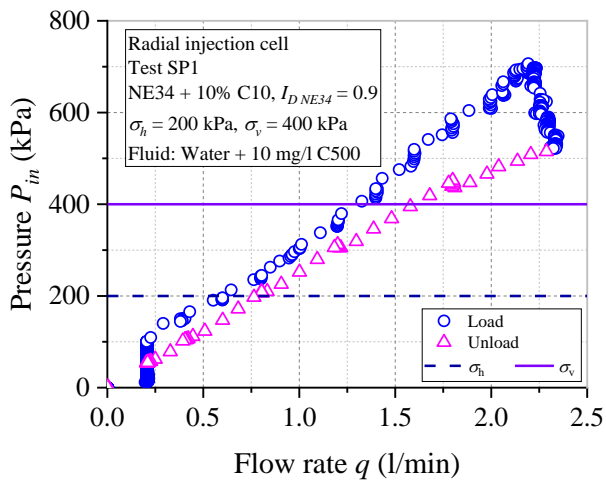
Fig. 6: Experimental results of test SP1: (a) full response; (b) initial step of pure water injection; (c) phase 1 of suspended particles injection at a constant flow rate of 0.2 l/min; (d) phase 2 with a loading – unloading cycle of flow rate; (e) increase of the injection pressure in the matrix injection regime.

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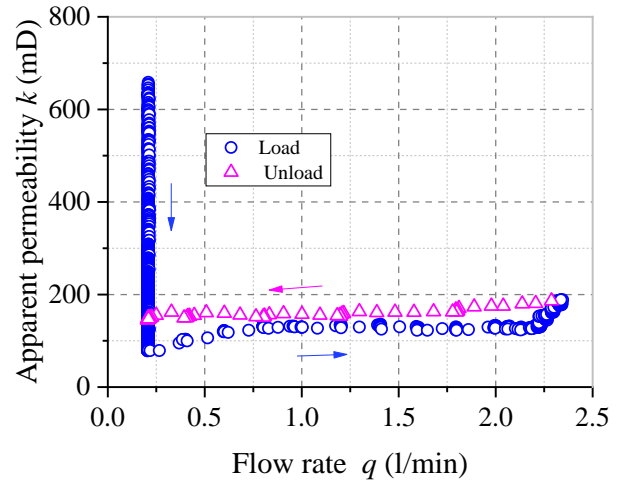
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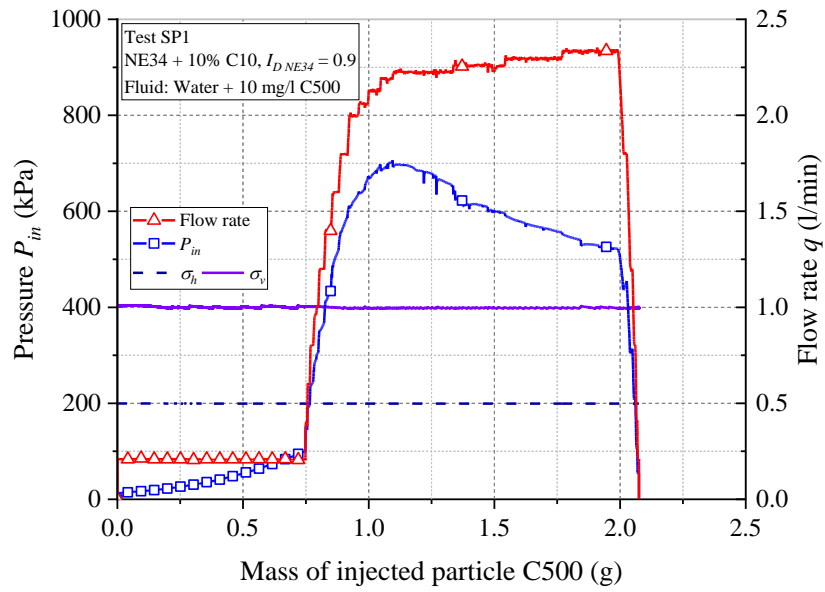
(a)



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(b)

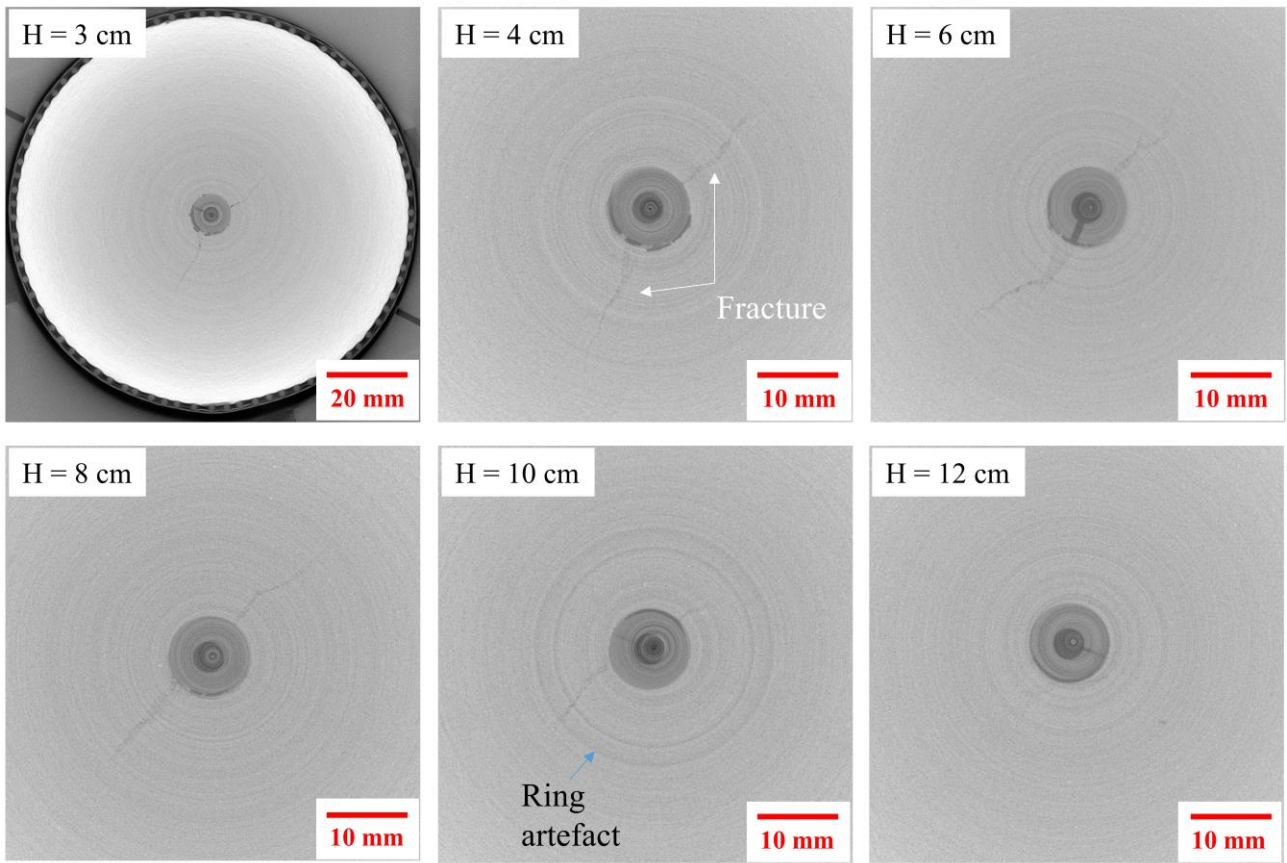
Fig. 7: Results of test SP1 (a) evolution of pressure; (b) evolution of apparent permeability.



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Fig. 8: Cumulative mass of injected C500 particles during the experiment SP1.

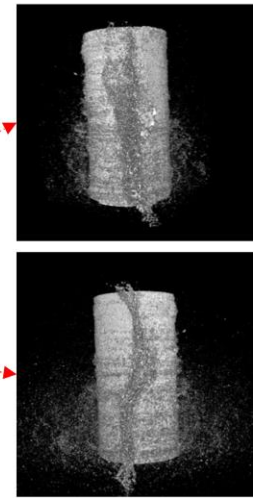
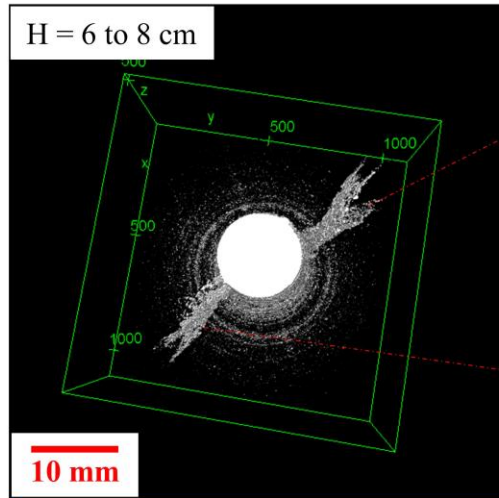
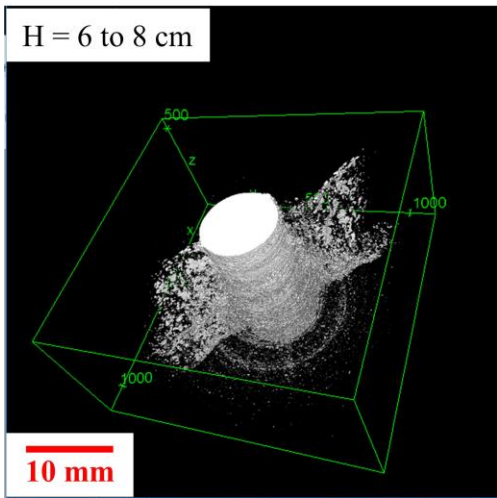
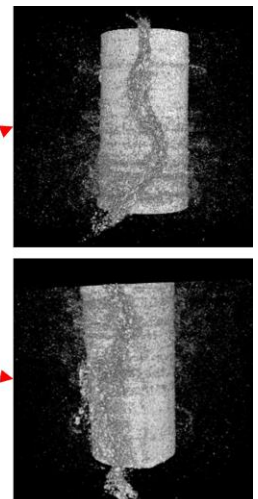
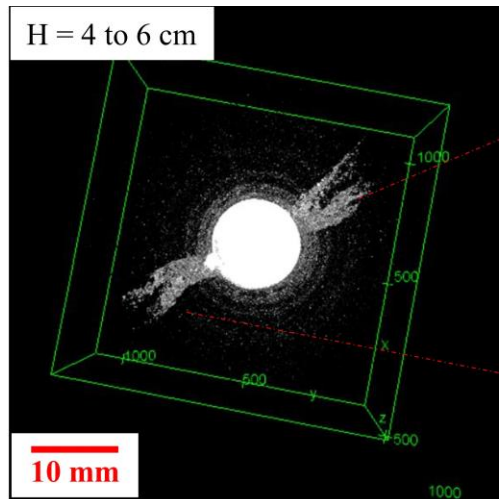
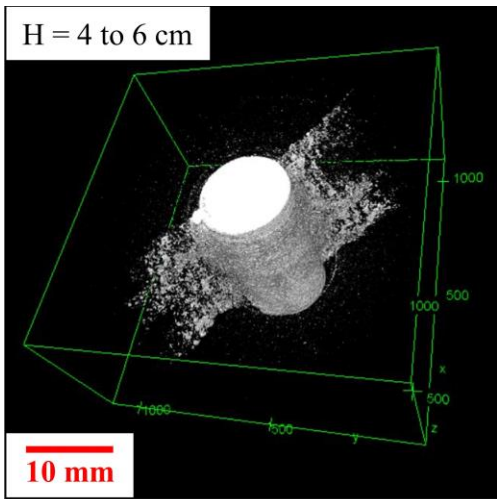


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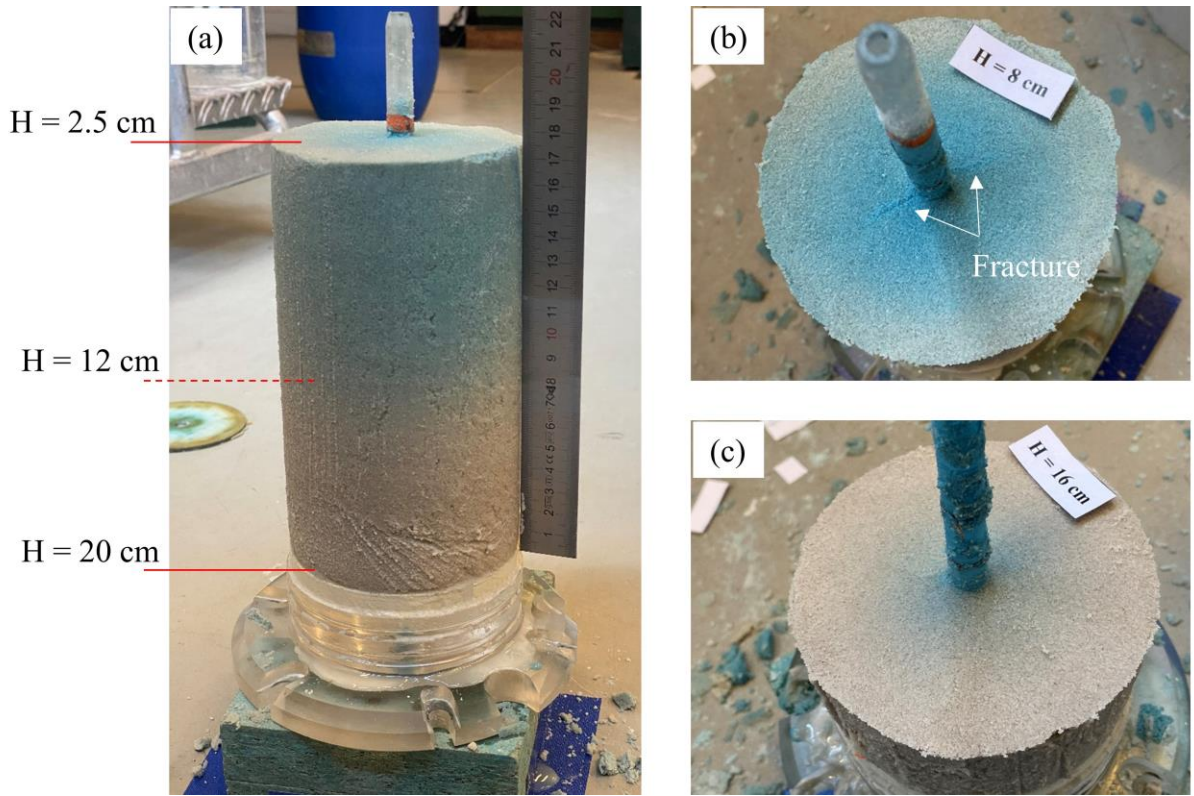
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Fig. 9: Selected X-ray CT images at different heights of specimen SP1.



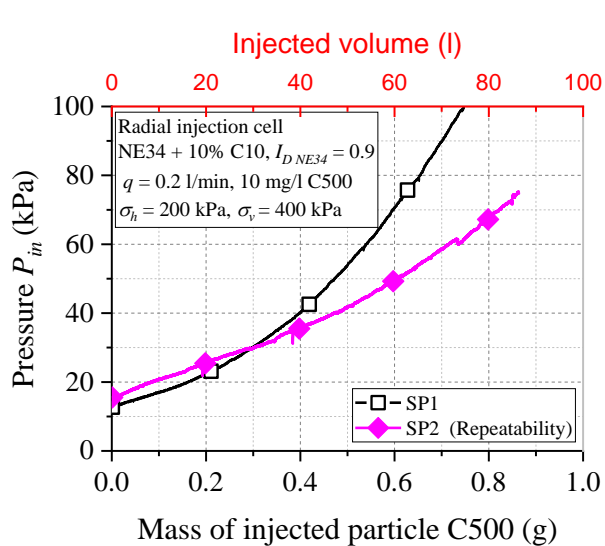
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Fig. 10: 3D views of fractures developed along two different sections of specimen SP1: Section 1 from H = 4 to 6 cm and Section 2 from H = 6 to 8 cm.

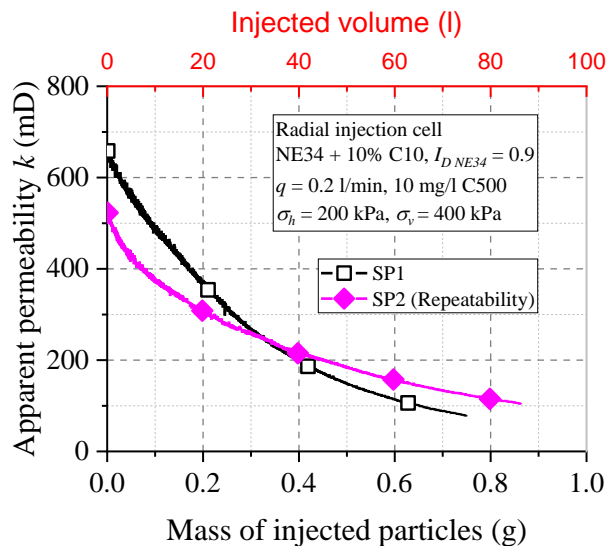


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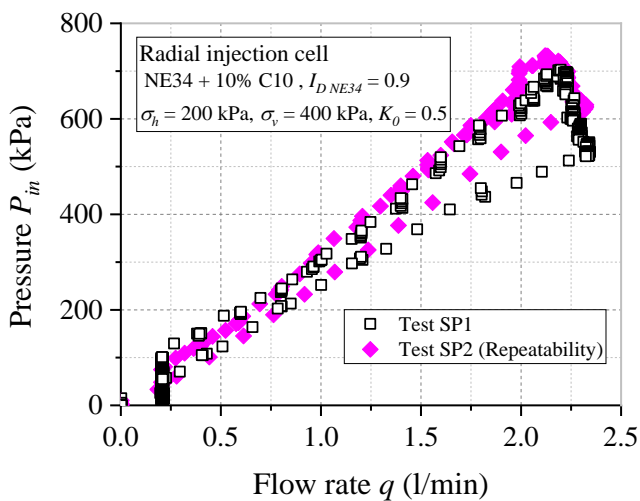
591 Fig. 11: Views of the specimen post-mortem: (a) global view; (b) and (c) horizontal cross-section at
592 $H = 8 \text{ cm}$ and $H = 16 \text{ cm}$ respectively.



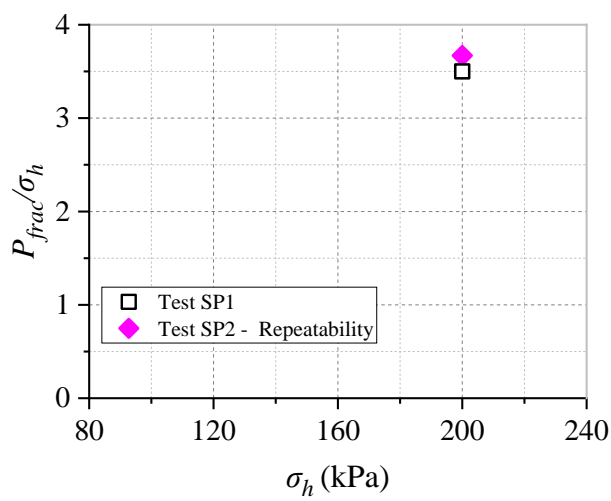
(a)



(b)



(c)



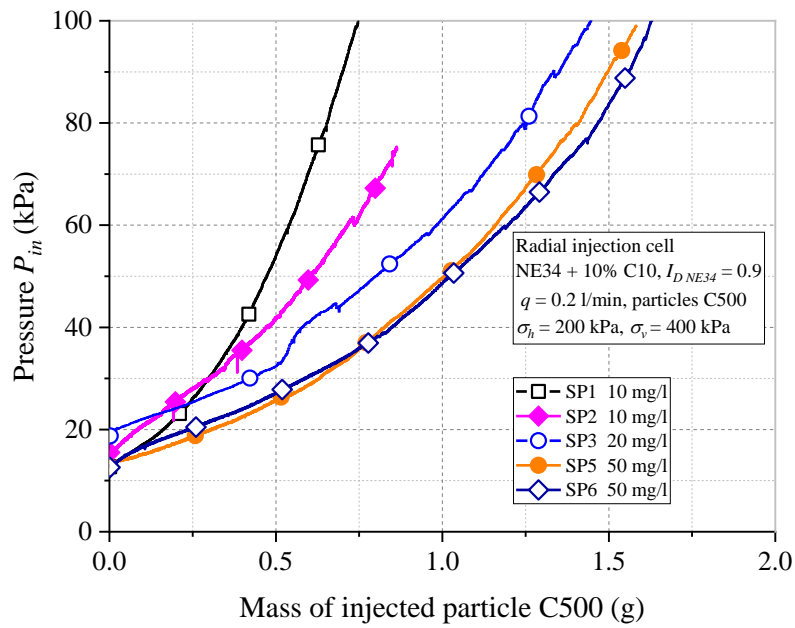
(d)

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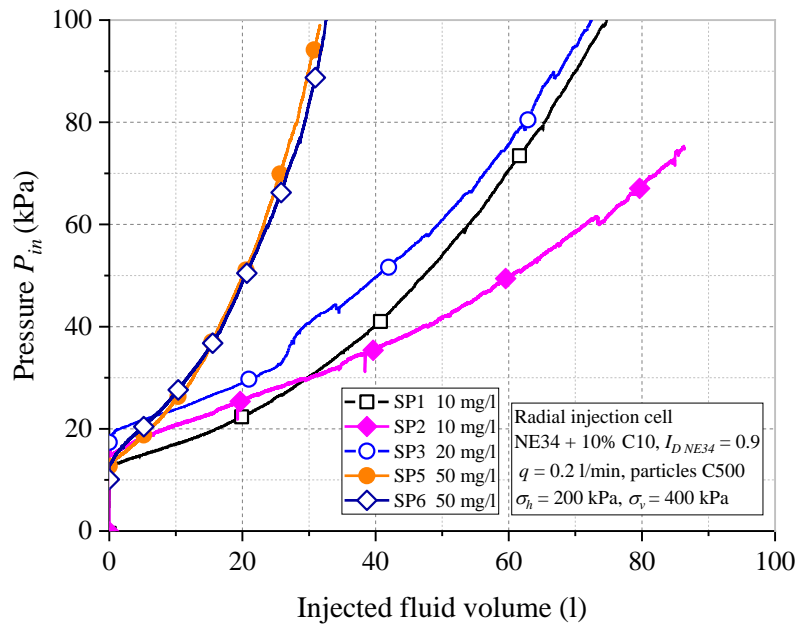
595 Fig. 12: Repeatability tests during the plugging phase: (a) evolution of the injection pressure (b)
 596 apparent permeability and during fracturing phase: (c) pressure – flow rate curve; (d) normalized
 597 fracturing pressure (P_{frac}/σ_h).

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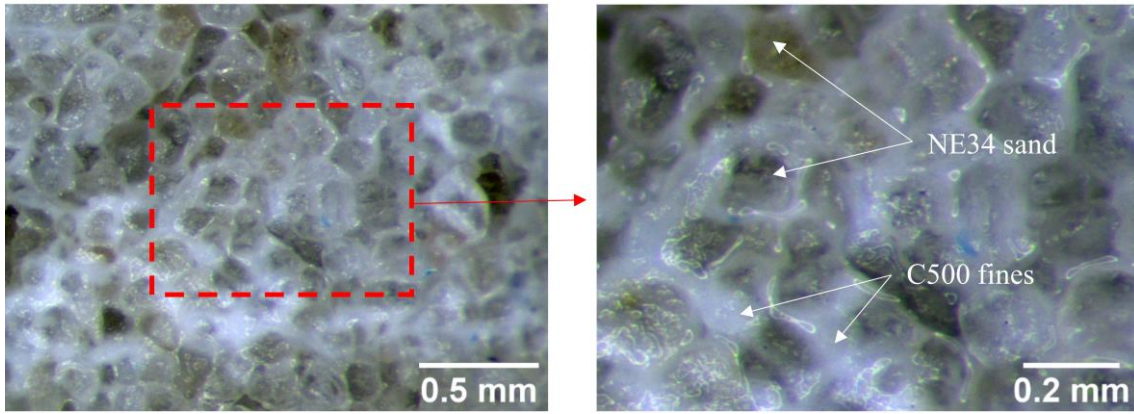
(a)



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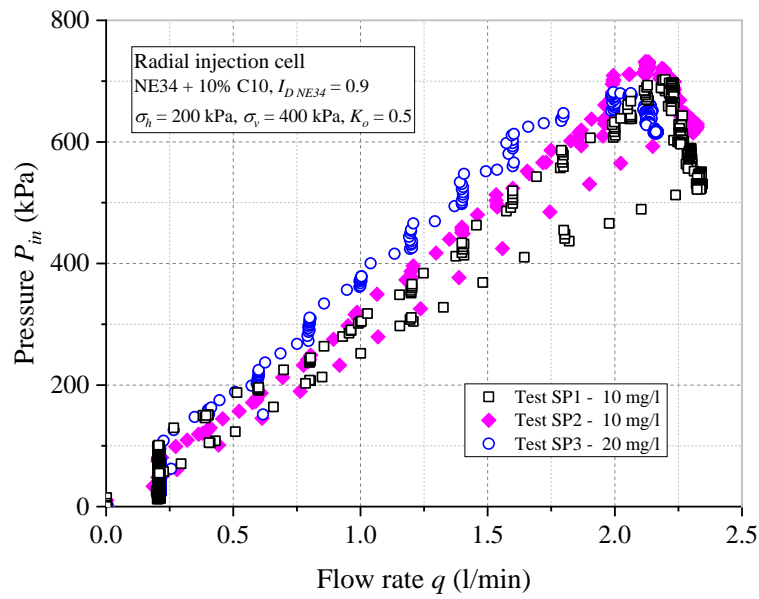
(b)

602 Fig. 13: Effect of the particles concentration on the plugging damage: (a) injection pressure versus
 603 mass of injected particles and (b) injection pressure versus injected fluid volume.



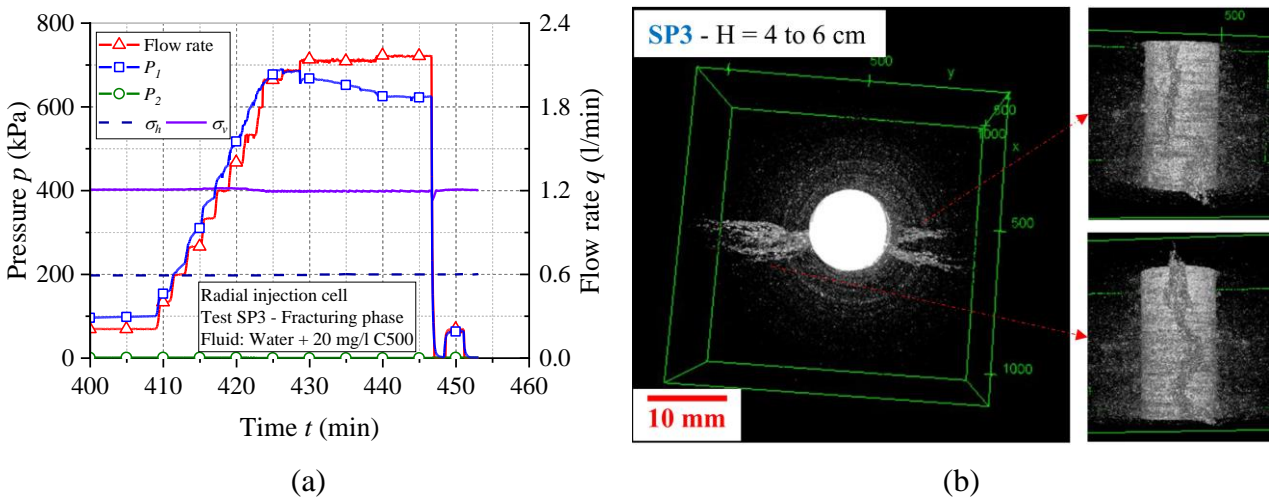
604

605 Fig. 14: Test SP5 - Optical microscope observation of the interface between specimen and 80 μm
 606 sieve covered the injection tube.



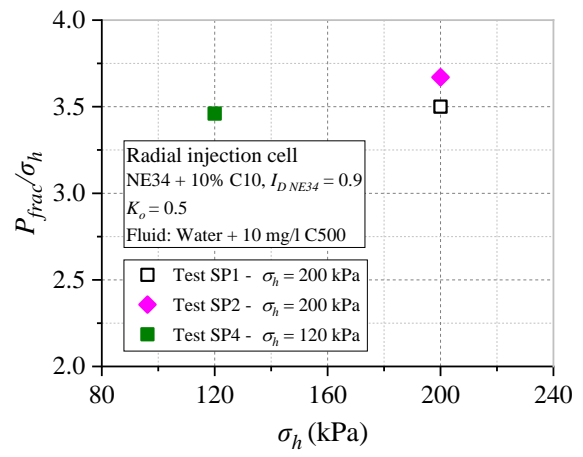
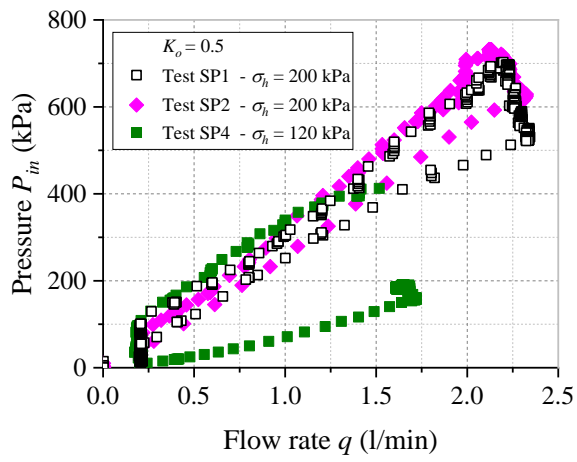
607

608 Fig. 15: Effect of the particles concentration on the fracturing response.



609

610 Fig. 16: Test SP3 (a) injection results during phase 2 (fracturing phase); (b) 3D views of the
 611 fractures induced along a section between $H = 4$ cm and $H = 6$ cm.



612

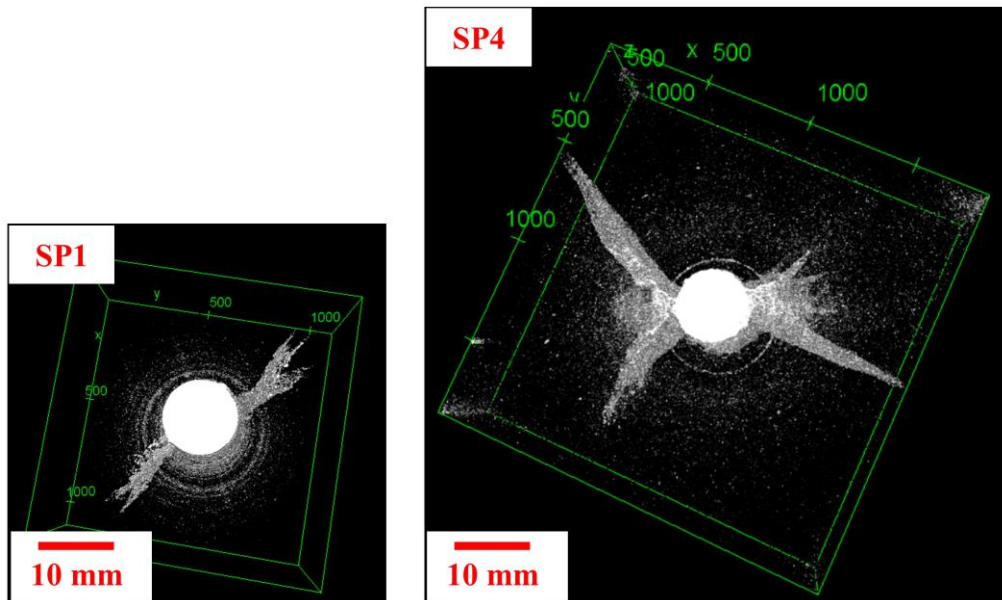
(a)

(b)

613

Fig. 17: Effect of the confining pressure on the fracturing response: (a) injection pressure versus flow rate; (b) normalized fracturing pressure.

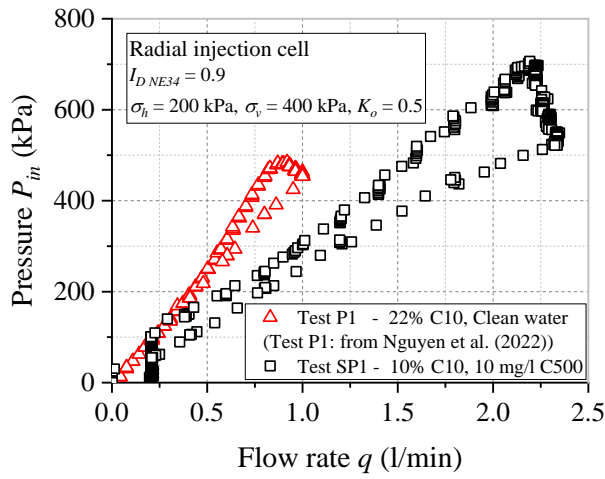
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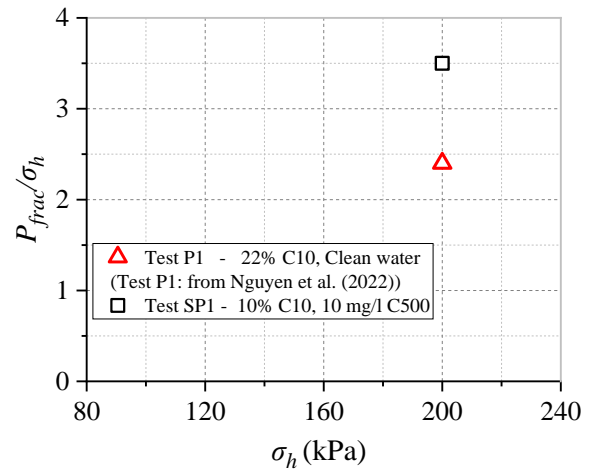
615

616

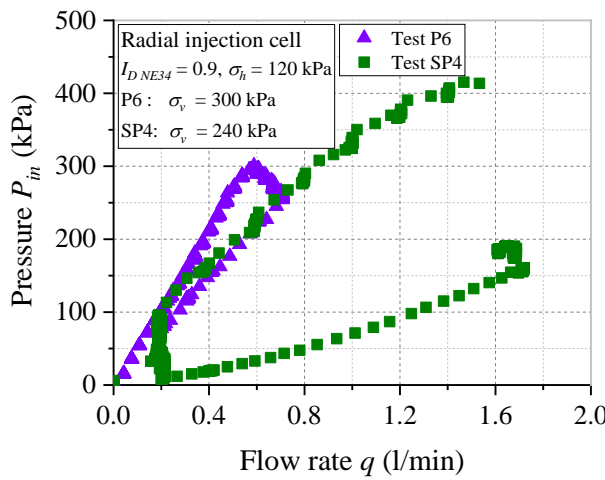
Fig. 18: 3D views of the fractures developed at the center of the specimens SP1 and SP4.



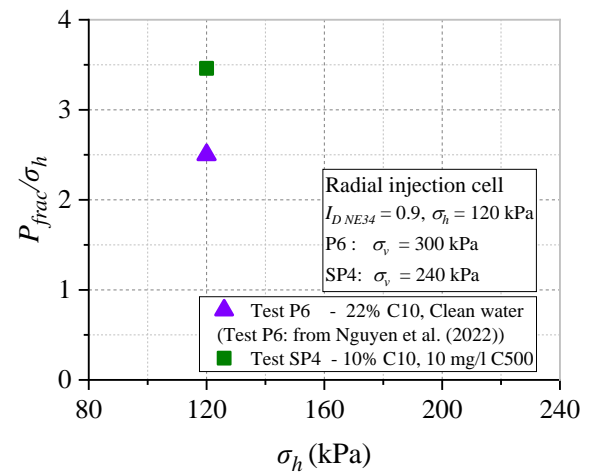
(a)



(b)



(c)



(d)

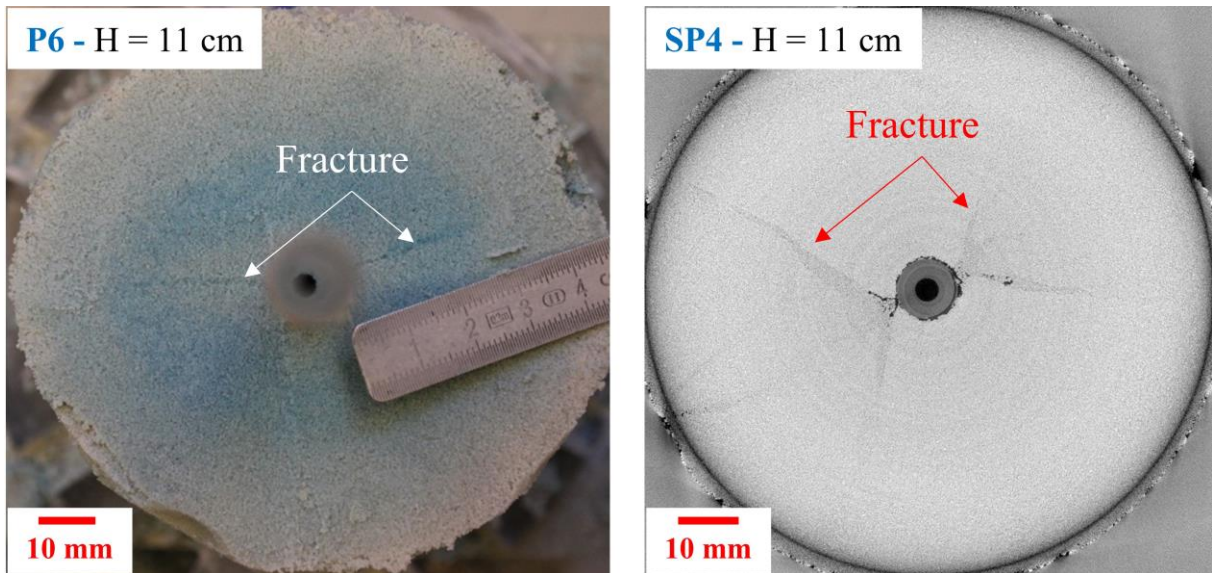
617

618

619 Fig. 19: Results comparison of two injection scenarios (pure water: Nguyen et al., 2022) and water
 620 containing suspended particles) at the same stress conditions: (a) and (c) injection pressure versus
 621 flow rate; (b) and (d) normalized fracturing pressure (P_{frac}/σ_h).

622

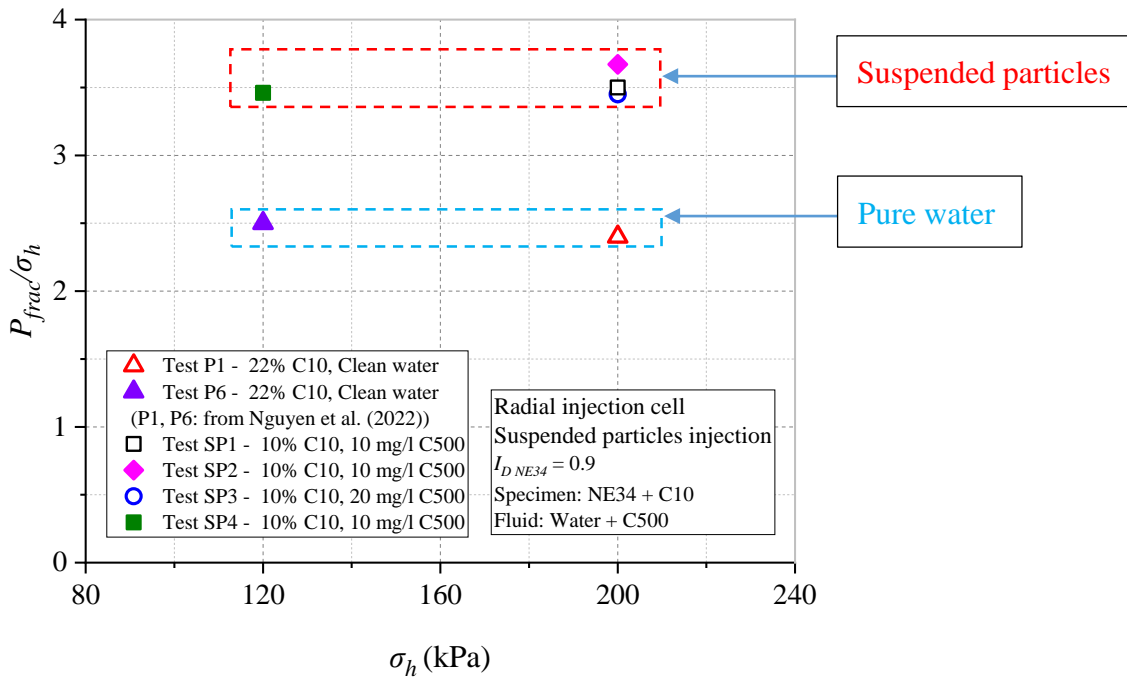
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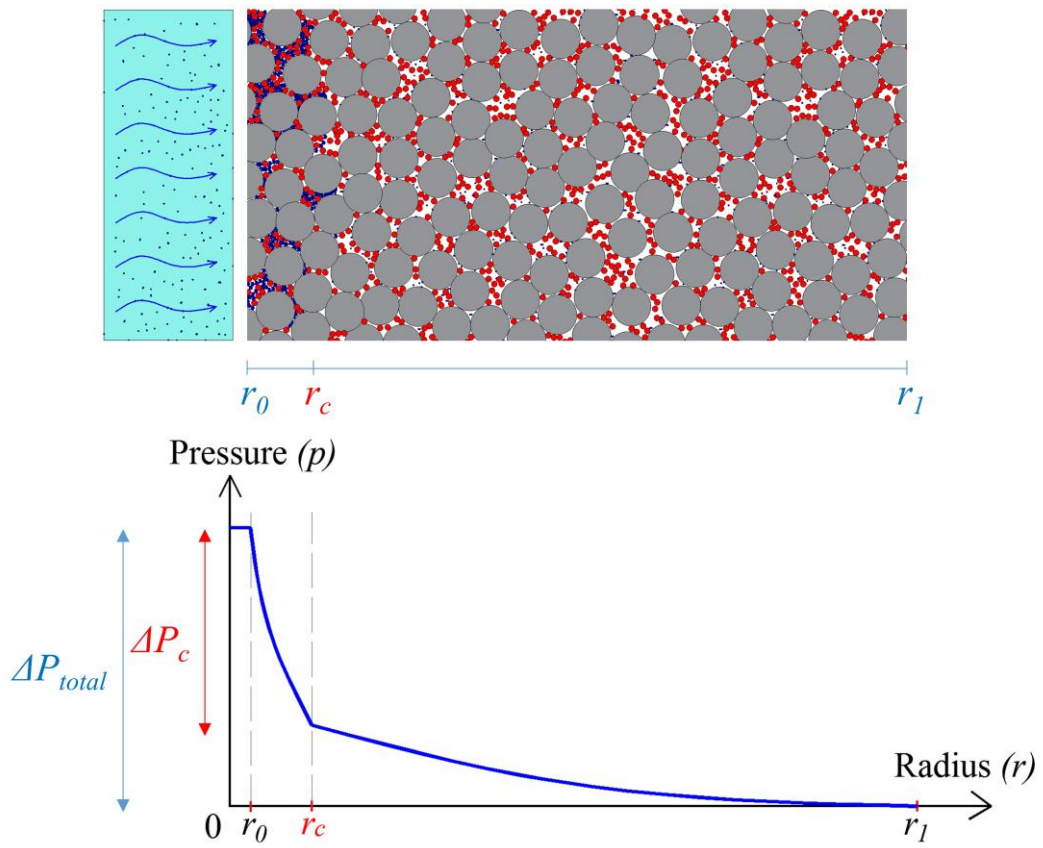
Fig. 20: Typical fracture patterns observed in two scenarios at the same confining pressure of 120 kPa (Pure water – Test P6: Nguyen et al., 2022), Suspended particles – Test SP4).



627

628
629

Fig. 21: Synthesis of the normalized fracturing pressure with the two scenarios: pure water and suspended particles injection.



630

631 Fig. 22: Schematic representation of the pressure distribution within the clogged specimen by
 632 entrance cake formation.

633

634

Material	D_{50} (μm)	C_u	e_{min}	e_{max}	Angularity	ρ_s (g/cm^3)
Fontainebleau NE34 sand	210	1.5	0.55	0.88	Sub-rounded	2.65
C10 fine particles	20	11	-	-	-	2.65
C500 fine particles	4.5	4.5	-	-	-	2.65

635 Table 1: Characteristics of the tested materials.

636

Section	Heigh (H)	Materials	Total mass (m)	$I_{D\ NE34}$	Porosity (n)	Dry density (ρ_d)
	cm					
Upper and lower layers of low permeability	2	NE34 + 32% C10	322	0.6	22	2.08
Injection zone	16	NE34 + 10% C10	2290	0.9	31	1.84

637 Table 2: Characteristics of the reference specimen.

638

Test	Fluid		Stress conditions			Density index of the matrix $I_{D\ NE34}$	Injection protocol
	μ (cP)	% C500 (mg/l)	σ_h (kPa)	σ_v (kPa)	K_0		
SP1	1	10	200	400	0.50	0.90	
SP2	1	10	200	400	0.50	0.90	- Phase 1 (plugging phase)
SP3	1	20	200	400	0.50	0.90	Injection at $q = 0.2$ l/min
SP4	1	10	120	240	0.50	0.90	- Phase 2 (fracturing phase)
SP5*	1	50	200	400	0.50	0.90	Gradual increase of the flow rate until fracturing of the specimen
SP6	1	50	200	400	0.50	0.90	

639 * test SP5 was performed with only the plugging phase

640 Table 3: Characteristics of the sensitivity tests.