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# An experimental setup with radial injection cell for investigation of fracturing in unconsolidated sand reservoirs under fluid injection

Thanh Tung Nguyen<sup>(1)</sup>, Jean Sulem<sup>(1)</sup>, Rawaz Dlawar Muhammed<sup>(1)</sup>, Jean-Claude Dupla<sup>(1)</sup>, Jean Canou<sup>(1)</sup>, Jean-Grégoire Boero-Rollo<sup>(2)</sup>, Jalel Ochi<sup>(2)</sup>

(1) Laboratoire Navier, Ecole des Ponts ParisTech, Univ. Gustave Eiffel, CNRS, Marne-la-Vallée, France

(2) TotalEnergies, Pau, France

## Highlights

- A new experimental device is developed for studying hydraulic fracturing of dense sand specimens.
- Fractures are not tensile cracks but appear as localized zones of higher porosity and larger pore size resulting from dilatant shearing and fine particles transport.
- Higher flow rate enhances fine particles transport which results in the extension and the opening of the pseudo-fractures.
- The fracturing pressure is controlled by the confining pressure and does not change significantly with the stress ratio and with the initial permeability of the sand specimen.

## Abstract

Formation damage and the associated injectivity loss of wells induced by the produced water re-injection can be often overcome by injecting in the fracturing injection regime. This paper presents an experimental investigation of fracturing mechanisms induced in unconsolidated sand reservoirs under fluid injection using a new radial injection setup. The development of the injection cell is based on a radial injection configuration within a classical triaxial cell to simulate the injection wells conditions and this cell allows the whole specimen to be scanned using X-ray Computed Tomography (X-ray CT). Typical test results exhibit pressure drops during fluid injection corresponding to fracturing of the specimen, and consequently to an increase of the overall permeability. This can be confirmed by the detection of small radial fractures ('pseudo-cracks') around the injection point either by visual observation when disassembling the specimen or by 3D X-ray CT. Fractures appear as localized zones of higher porosity and larger pore size resulting from dilatant shearing and subsequent particles transport. The impact of various parameters (confining pressure, stress ratio coefficient, flow rate, permeability) on the fracturing process in sand specimens is explored. The obtained experimental results suggest that confining pressure is a key parameter controlling fracture initiation.

Keywords: Radial injection cell, Fracturing flow regime, Fracturing mechanisms, PWRI, Unconsolidated sand reservoirs, X-ray Computed Tomography.

## 45 1. Introduction

46 In hydrocarbon producing fields, Produced Water Re-Injection (PWRI) is known as an economically  
47 attractive and environmentally friendly method for managing produced water. This method has the  
48 advantage of pressure maintenance support and sweeping efficiency in order to enhance the hydrocarbon  
49 production (Farajzadeh, 2004; Souilah et al., 2014). However, despite many treatment processes, there  
50 is always a small amount of impurities, such as suspended solid particles of several microns and oil  
51 droplets in the injected water (Mainguy et al., 2020). Once the produced water is re-injected into  
52 reservoirs, the filtration of these components around the injection well leads to progressive clogging of  
53 the medium, and consequently, to the decline of the injectivity (Al-Abduwani et al., 2005; Li and Wong,  
54 2008; Feia et al., 2015, 2017). The formation of filter cakes, due to the deposited solid particles in the  
55 near-wellbore region, is viewed as the dominant mechanism of the formation damage (i.e. permeability  
56 decrease) during PWRI (Shutong and Sharma, 1997). This issue is of particular importance for  
57 unconsolidated sand reservoirs. Although the formation has a high initial porosity and a high  
58 permeability (of the order of few Darcy), transport and deposition of suspended particles carried by the  
59 produced water deteriorate the well injectivity. Once formation damage occurs, several treatments can  
60 be applied for improving well injectivity in the matrix flow regime such as clean water injection (to flush  
61 away a fraction of deposited particles in the near-wellbore region) or chemical additives injection (to  
62 destabilize the filter cake and to clean the sand controls screen) (Souilah et al., 2014; Mainguy et al.,  
63 2020). Using these techniques may partially restore the injectivity loss but the beneficial effect  
64 disappears soon after PWRI resumes and these techniques require a substantial cost compared to the  
65 benefits they bring. On the other hand, re-injection in the so-called ‘fracturing regime’ is an option to  
66 maintain the injectivity by fracturing the clogged zone formed by the agglomeration of fine particles at  
67 the face of the injected formation (Ochi et al., 2014; Mainguy et al., 2020). However, controlling the  
68 injection in the fracturing regime is a key issue for the safety of the production as possible loss of  
69 fractures containment could deteriorate the cap rock integrity (Onaisi et al., 2011).

70 Hydraulic fracturing is commonly applied in consolidated rock reservoirs for enhancing oil and gas  
71 production. The first experimental fracturing was conducted in the Hogoton field in 1947 (Montgomery  
72 et al., 2010) Since that time, hydraulic fracturing has been one of the primary engineering tools for  
73 enhancing oil recovery. It is estimated that more than 90% of gas wells and 70% of oil wells throughout  
74 the world apply this technique (Economides and al., 2007). In the case of consolidated and brittle  
75 formations (e.g. hard rocks) with low permeability, hydraulic fracturing has been extensively studied  
76 (Detournay, 2016). Fracturing is dominated by tensile failure and conventional modeling is based on  
77 Linear Elastic Fracture Mechanics (LEFM) (Fjaer et al., 2008). Fracturing of soft rock formations, on  
78 the other hand, results in a higher net fluid pressure, shorter and wider fractures as compared to those  
79 obtained in a strong elastic formation because of the development of plastic zones at the fracture tip  
80 during fracture propagation and fluid leak off in the porous rock (Papanastasiou, 1997, 1999; Sarris and  
81 Papanastasiou, 2013). However, the dominant mechanism of fracturing in soft rocks is also tensile failure  
82 and fracture propagation is controlled by the rock toughness.

83 The mechanisms involved in fracturing of unconsolidated sand reservoirs, which are studied in the  
84 present work, are fundamentally different than the ones involved in brittle fracturing. Due to the  
85 negligible tensile strength as well as the extremely large fluid leak-off, the possibility of tensile failure  
86 is suppressed in favor of shear failure (Bohlooli and de Pater, 2006; Zhai and Sharma, 2005), fluidization  
87 (Chang, 2004; Wu, 2006) or flow-induced channelization around an injection point (Ameen and  
88 Taleghani, 2015; Bautista and Taleghani, 2018; Mahadevan et al., 2012). During the last two decades,

89 several experimental studies have been dedicated to investigate the mechanisms and develop appropriate  
90 modeling of hydraulic fracturing in unconsolidated or poorly consolidated materials. However, the exact  
91 mechanisms involved in the fracturing process still remain an open issue. Khodaverdian and McElfresh,  
92 2000 have performed a series of hydraulic fracturing experiments in a radial flow cell (RFC), which is  
93 a half-cylinder (3-ft of radius). However, injection was performed through a rigid tube containing only  
94 some open holes that could not provide a radial configuration.

95 Bohloli and de Pater (2006); de Pater and Dong (2007); (2009); Dong (2010); Zhou et al. (2010)  
96 have conducted different experimental programs in axisymmetric cell to investigate the hydraulic  
97 fracturing for cohesionless soils. Different configurations of injection tube have been used such as the  
98 porous tube, the slotted open hole, open-hole interval, depending on the purpose of the research. Dong  
99 (2010) has used a similar axisymmetric cell (CT cell) with a smaller specimen size, allowing to visualize  
100 the fracture geometry in real-time by X-ray CT scanning. The CT cell is made of aluminum, which is  
101 able to apply a high confining pressure up to 20 MPa and is still X-ray transparent. However, as the  
102 image resolution of the CT scanner used in their study is rather limited as the smallest voxel size is of  
103 300  $\mu\text{m}$ , which is larger than sand grains size. Therefore, only large open fractures could be observed.  
104 An interesting work on hydraulic fracturing in cohesionless sand has been conducted by Golovin et al.,  
105 (2010), (2011); Jasarevic et al. (2010); Chudnovsky et al. (2015); Wong et al. (2017). These authors  
106 have developed a special device for conducting hydraulic fracturing under 3D stress conditions. A cubic  
107 chamber with a dimension of 2ft ( $\approx 61$  cm) for each edge is used. Nevertheless, the fluid was injected  
108 only through two opposing perforations (2 mm diameter) that provided a localized flow in the specimen  
109 which cannot simulate the radial flow conditions of PWRI as performed in the field. Another interesting  
110 study on hydraulic fracturing in particulate materials has performed by Chang (2004); Wu (2006);  
111 Germanovich et al. (2012); Hurt (2012).

112 Most of the studies mentioned above refers to frac-packing treatment or polymer flooding since they  
113 have been performed with very viscous fluids or with fluids containing a high concentration of solid  
114 particles with a high flow rate in order to enhance fracturing of the unconsolidated sand. Very few studies  
115 focus on the fracturing in the situation of PWRI in which the injected fluid has a very low viscosity (of  
116 the order 1 cP) and a low concentration of solid particles and in which the injection is maintained over  
117 a long period of time (Onaisi et al., 2011). In the present work, we aim at reproducing more realistic  
118 injection conditions by developing a new radial injection setup which permits to generate a radial flow  
119 through a cylindrical sand specimen under axial and radial confining stresses. The main objective of this  
120 work is to study the conditions for reaching the frac-regime and explore the fracturing mechanisms  
121 induced by the radial water injection in sand specimens containing particles which represents the clogged  
122 zone around the injection well due to PWRI. The experimental device and the experimental results are  
123 described in the following together with the observation of the fractured specimen using X-ray  
124 Computed Tomography (X-ray CT) and optical microscopy.

## 126 2. Experimental setup

127 A radial injection cell has been specially designed and built to study fracturing mechanisms in  
128 unconsolidated sand specimens under fluid injection. The main innovation in this new experimental  
129 setup is that it permits small scale observations using CT scanner. Thanks to a high resolution of X-ray  
130 CT in our laboratory, we could achieve a resolution of 29  $\mu\text{m}$  per voxel. Specimens contain grains with  
131 a mean grain size  $D_{50}$  of 210 microns and fine particles of 20 microns. Therefore, it is possible to observe  
132 the microstructure of the specimen at the grain scale. Note that, for example, this resolution is 10 times  
133 higher than the one used in the work of Dong (2010). Another important feature of the experimental

134 device is the possibility to mimic the real injection process in the field by imposing a radial flow in the  
135 specimen by using a central injection tube. This tube contains open holes drilled in a helical groove. A  
136 lateral drainage system is installed around the specimen. This system permits to generate a radial flow  
137 which is homogeneous along and around the tube.

138 **Fig. 1** shows a schematic cross section of radial injection cell with some of its major components. A  
139 cylindrical sand specimen of 100 mm in diameter and 200 mm in height with a controlled prescribed  
140 density can be built in the cell which is basically a classical triaxial cell with independent application of  
141 a confining stress and of an axial stress. In order to avoid the absorption of X-ray and metal artifact  
142 during scanning, the cell is fabricated with a limited number of metal pieces and can be easily  
143 transported. In particular, the scanned part (red rectangular in **Fig. 1**) is made of polymethyl methacrylate  
144 (PMMA) to facilitate the penetration of X-ray.

145 The cell consists of the following major components: an upper baseplate, a lower baseplate, a central  
146 tube attached to the lower baseplate, a peripheral drainage system, a lateral latex membrane and a  
147 confinement chamber. The upper and lower baseplates both consist of two separated pieces: one in  
148 PMMA and another in aluminum. Two rubber O-rings are positioned between the two pieces for sealing.  
149 The drainage system consists of two polyamide fabric sieves of cylindrical shape with an opening mesh  
150 of 80  $\mu\text{m}$ , which allow for the retention of sand grains and for the passage of fine particles. The rubber  
151 O-rings are glued between these two sieves for maintaining a sufficient space for drainage and flow out  
152 of the fluid. **Fig. 2** shows a 3D schematic cross-section of the upper part of the cell with the drainage  
153 system for the fluid flow within the cell. On the upper baseplate, there are one outlet of the injection tube  
154 and two outlets of the lateral drainage system. Six small holes of 2 mm in diameter, drilled symmetrically  
155 inside the PMMA piece, allow to link the lateral drainage system with two outlets of the upper baseplate.  
156 The configuration of the central tube, made in PMMA, is presented in **Fig. 3a**. The inner and outer  
157 diameter of the central tube are 4 mm and 10 mm, respectively. Open holes are perforated on the helical  
158 groove, allowing to provide a radial fluid flow along the tube. The injection tube is covered by a 80  $\mu\text{m}$   
159 sieve to prevent the inflow of sand into the injection tube (**Fig. 3b**).

160 **Fig. 4** and **Fig. 5** present a functional scheme and a general view of the experimental setup  
161 respectively. Injection was carried out with a G03 Hydra-Cell Pump at a constant flow rate with a range  
162 between 0.1 l/min and 2 l/min. A pulsation dampener, installed at the outlet of the pump, is used to  
163 reduce the pressure fluctuations and flow pulsations during injection. The injection rate is measured with  
164 a flowmeter installed at the inlet of the specimen. Three pressure transducers permit to monitor the  
165 confining pressure and the injection pressure at the inlet and at the outlet of the specimen. The accuracy  
166 of these sensors is of 0.5 kPa. The vertical stress is applied to the specimen through a 50 kN mechanical  
167 press Tri-SCAN. The axial force is measured using a force transducer installed on the top of the cell.  
168 The maximum capacity of the sensor is 10 kN with a measure accuracy of 0.004 kN. The confining  
169 pressure is applied using an air-water pressurization cell which has a maximum capacity of 1 MPa. All  
170 the measurement systems are connected to a computer through a multi-meter, allowing for automatic  
171 data acquisition and display of data in real time during the test. The acquisition frequency is manually  
172 set to one data point per 3 seconds.

### 173 3. Materials

174 In order to represent the clogged area around injection wells due to PWRI, the specimens of dense  
175 mixture of sand and fine particles are reconstituted by compaction. Fontainebleau NE34 sand and C10  
176 silica particles are used. Fontainebleau sand has sub-rounded grains ( $D_{50} = 210 \mu\text{m}$  for NE34) and is  
177 composed of 99% silica. C10 is also composed of silica particles ( $D_{50} = 20 \mu\text{m}$ ), allowing to avoid any  
178 chemical interaction with NE34 sand. Its physical properties are similar to those of NE34 sand. The main  
179 characteristics of these materials are presented in **Table 1**. **Fig. 6** presents the grain size distribution of  
180 both materials obtained from laser diffraction analysis. The preparation of the mixture of NE34 sand and  
181 C10 particles is carried out using a mixer and its homogeneity is validated by analyzing samples  
182 containing different concentrations of C10 particles (10% and 20%) using laser granulometer. The  
183 particles concentration is defined as the percentage in mass of C10 particles to NE34 sand ( $m_{C10}/m_{NE34}$ ).  
184 As can be seen in **Fig. 6**, a good consistency in terms of the grain size distribution of the mixture is  
185 observed. Microscopic views of pure NE34 sand and of NE34 sand mixed with 22% of C10 particles  
186 are presented in **Fig. 6b,c**.

187 In the experiments, a colloidal silica is used to solidify the specimen after fracturing. It is a stable  
188 aqueous suspension (colloid) of nanometric silica particles. The particles size is between 7 and 22 nm  
189 (Gallagher and Lin, 2009). The nanosilica suspension can be gelled by raising the pH or changing ionic  
190 strength of the solution. The gel time depends on the interaction rate between particles, which is  
191 influenced by many factors such as the silica particle size, the ionic strength, the pH, and the temperature  
192 (Persoff et al., 1999).

193 The colloidal silica used in this research is commercially referenced as MasterRoc MP320. It was  
194 provided by BASF Construction Chemical Company. A sodium chloride solution (called an accelerator)  
195 is added to MasterRoc MP320 at the required ratio to obtain adequate gel times. The preparation of the  
196 accelerator consists of dissolving 10% by mass of salt in water. The characteristics of the product are  
197 shown in **Table 2**. The initial properties of colloidal silica are similar to those of water. **Fig. 7a** presents  
198 the gel time of MasterRoc MP320 with varying accelerator dosage. It makes evidence that higher dosage  
199 of accelerator results in shorter gel time. The results of diluted the colloidal silica before adjusting the  
200 accelerator are also presented in **Fig. 7a**. Gelification time increases with the decrease of the silica  
201 concentration in the mixture. To better visualize the fractures within the specimen during manual  
202 disassembling, a dye called Basacid® Blue 762 was added into the colloidal silica before injection (**Fig.**  
203 **7b**). It is a water based anionic dye solution, allowing to inject into the sand specimen without any  
204 filtration.

### 205 4. Test procedure and specimen preparation

206 The test procedure consists of the following operations: fabrication and initial scan of the specimen  
207 using X-ray CT (Scan 1); saturation and application of the initial stress conditions; water injection by  
208 gradually increasing flow rate by steps until fracturing; colored gel injection to solidify the specimen  
209 after fracturing; second scan of specimen after fracturing using X-ray CT (Scan 2); and finally, manual  
210 disassembling and optical microscopy observation of the specimen. **Fig. 8** presents the configuration of  
211 the reconstituted specimen tested in this study which consists of three zones: the injection zone and two  
212 layers of lower permeability at the top and bottom. Two small membranes are placed between these  
213 layers (i.e., between injection zone and low permeability layer) in order to ensure full radial flow and  
214 prevent vertical flow out of the injection zone. These two layers of lower permeability contain 32% of  
215 C10 particles which is higher than the particles concentration of the injection zone (22% for the reference  
216 test). The specimen is prepared in dense state (density index of the NE34 sand matrix of 0.90).

217 The density index of the sand matrix  $I_{D\ NE34}$  is defined as:

$$I_{D\ NE34} = \frac{e_{max}^{NE34} - e^{NE34}}{e_{max}^{NE34} - e_{min}^{NE34}} \quad (1)$$

218 where  $e_{max}^{NE34}$ ,  $e_{min}^{NE34}$ ,  $e^{NE34}$  are the maximum void ratio, the minimum void ratio and the void ratio  
219 of NE34 pure sand matrix (without fines).

220 By changing the concentration of C10 particles, we can change the permeability of the various layers  
221 of the specimen. Note that by keeping the same density index of the NE34 sand matrix and for the  
222 concentration of fine particles used in the tests, the structure of the sand pack remains unchanged  
223 (Cubrinovski and Ishihara, 2002). The characteristics of the reference specimen which contains 22% of  
224 C10 particles in the injection zone are presented in **Table 3**.

225 **Fig. 9** shows the main steps of the specimen preparation. Firstly, some glass beads are glued on the  
226 lower plate as reference points, allowing to orient the scanned images in initial and post-fracturing states  
227 in the same position (**Fig. 9a**). The injection tube and drainage system are then fixed on the lower  
228 baseplate (**Fig. 9b**), followed by the installation of a 0.3 mm thick latex membrane and a cylindrical  
229 mold composed of two parts. The vacuum is then applied to press the membrane onto the mold (**Fig.**  
230 **9c**). The mold is also made by PMMA to be compatible with X-ray CT scan (**Fig. 9d**). The specimens  
231 are reconstructed by dry compaction of ten layers of 2 cm using a groomer, specifically designed for this  
232 cell (**Fig. 9e**). After compacting the first lower permeability layer, a small latex membrane is placed on  
233 the top. This membrane is covered with grease to prevent any flow along its surface (**Fig. 9f**). Then, the  
234 injection zone of the specimen is built with eight layers and compacted and another small membrane is  
235 fixed on the top of the injection zone (**Fig. 9g&h**). The compacted surface of each layer is scarified prior  
236 to filling the following layer to avoid any artifacts due to manual compaction. When the compaction is  
237 done with the upper layer of lower permeability, a porous plastic disk is placed on the top of the specimen  
238 before setting up the upper baseplate (**Fig. 9i**).

239 Once the specimen is reconstituted, it is scanned using X-ray CT in order to build a reference 3D  
240 image of the specimen. After that, the cell is fixed to the Press Tri-SCAN (**Fig. 9k**). A vacuum of  
241 approximately -20 kPa is then applied to the specimen to take the mold out. The specimen is consolidated  
242 at an isotropic stress of 50 kPa before saturation (**Fig. 9l**). The saturation procedure consists of two steps.  
243 First carbon dioxide (CO<sub>2</sub>) is circulated under a pressure of 20 kPa for 10 to 15 minutes in order to expel  
244 the air present in the pores and then de-aired water is injected by gravity through the central tube. After  
245 saturation is completed (Skempton coefficient B value > 0.9), the specimen is loaded to the desired stress  
246 conditions.

247 Tests are performed at controlled flow rate. This procedure permits to reach the fracturing regime  
248 and to pursue the injection beyond the critical threshold corresponding to the maximum injection  
249 pressure (fracturing state) by further increase of the flow rate. Various values of the maximum imposed  
250 flow rate can be chosen in order to reach various extents of the fractures. During the water injection  
251 phase, the flow rate is increased until the fracturing of the specimen corresponding to the first sharp drop  
252 of the pore pressure measured by the inlet pressure transducer. The injection rate is gradually increased  
253 by steps of 0.033 l/min. Each rate is maintained for approximately 1.5 minutes until the pressure  
254 stabilizes. When the first pressure drop occurs, the corresponding flow rate is maintained for 10 minutes  
255 before further increase. Three more injection steps are carried out before decreasing the injection rate to  
256 zero.

257 The gelling solution is prepared by manually mixing the colloidal silica MasterRoc MP320, the  
258 accelerator and 0.2% of Basacid Blue 762. Then, the the colored gel is immediately injected in order to  
259 avoid the undesired effect of an increase of the viscosity of the gel after adding the accelerator. The

260 injected volume of the gelling solution is about 50% of the voids volume of the specimen. The specimen  
261 is kept for few days under the stress conditions to solidify.

262 Once the specimen is solidified by the injected gel, the applied stresses are released and the mold is  
263 reinstalled to protect the specimen. Then, it is placed in the X-ray CT for scanning (Scan 2). After  
264 scanning the specimen, a second step of disassembling is performed which consists of a horizontal  
265 excavation of the specimen. In addition, a small part of the specimen containing a fracture is observed  
266 by optical microscopy to characterize the microstructure of the fracture at the grain scale.

## 267 5. Typical experimental results

268 In this section, the results of a reference test carried out in the radial injection cell are presented.  
269 First, we introduce the results during the water injection phase. Then, we present the observation of the  
270 specimen using different methods such as X-ray CT, manual excavation and optical microscopy. The  
271 main characteristics of this test are presented in **Table 4**.

### 272 5.1 Water injection phase

273 The pore pressure measurements are shown in **Fig. 10a** in which  $P_1$  and  $P_2$  are the measured pressure  
274 by the inlet and outlet pressure transducers (T1 and T2), respectively. The injection phase is performed  
275 in about 90 minutes. As the outlet pressure transducer is installed at the end of outlet pipe,  $P_2$  is at  
276 atmospheric pressure. In the matrix injection regime, we observed the gradual increase of the injection  
277 pressure at constant imposed flow rate (**Fig. 10b**). This phenomenon can be attributed to internal erosion  
278 corresponding to the migration and filtration of a certain amount of fine particles (C10) inside the  
279 specimen. These mobilized particles accumulate in the pore throats, causing a local clogging of the  
280 specimen, and consequently a decrease of the overall permeability. Similar observations have been also  
281 made by Xiao and Shwiyhat (2012). To limit this phenomenon, before reaching the fracturing regime,  
282 the injection time of each step is fixed to only 1.5 minutes. When the flow rate reached 0.9 l/min, the  
283 first pressure drop was observed and the corresponding peak pressure measured by the inlet pressure  
284 transducer was 490 kPa. This flow rate step was maintained for 10 minutes, and then the flow rate was  
285 further increased with three more steps: 0.93 l/min, 0.96 l/min and 1 l/min before decreasing the flow  
286 rate until stop pumping (**Fig. 10c**). In the frac-regime, increase of the flow rate always leads to pressure  
287 drops at the beginning of the step followed by the gradual decrease of the pressure which are the signs  
288 of the propagation of fractures within the specimen.

289 As the pressure transducers are installed outside of the specimen, one has to account for the loss of  
290 hydraulic head in the driving line (flexible connection tube of 4 mm in internal diameter, valve, hydraulic  
291 tee fitting) to evaluate the pore pressure in the injection zone of the specimen. The loss of hydraulic head  
292 caused by the drainage system was determined by performing a calibration test without the specimen.  
293 At a given flow rate, the pressure at the entrance of tube injection  $P_{in}$  can be calculated by subtracting  
294 the pressure loss of the inlet driving pipe from the pressure measured by inlet pressure transducer  $P_1$ . In  
295 this device, the inlet pressure transducer was installed at the same vertical position as the cell, therefore  
296 the effect of the hydrostatic pressure is negligible.

297 **Fig. 11** presents the test results in terms of pressure versus flow rate. This curve is plotted by using  
298 the corrected measurements of the pressure at the inlet of injection tube  $P_{in}$ . The critical fracturing  
299 pressure  $P_{frac}$  of 484 kPa corresponds to 2.42 times the confining pressure  $\sigma_h$ .

300 The permeability is calculated using Darcy's law for 2D radial flow, as:



$$k = \frac{\mu \cdot Q}{\Delta P_s \cdot 2 \cdot \pi \cdot h} \ln \frac{r_0}{r_1} \quad (2)$$

where :  $h$  is the height of injection zone,  $r_0$  et  $r_1$  are the radius of the injection tube and specimen, respectively,  $\Delta P_s$  is the pressure drop by the specimen at the injection flow rate  $Q$ ,  $\mu$  is the dynamic fluid viscosity.

Due to internal erosion, the overall permeability of the specimen decreases from an initial value  $k_{int}$  of 82.8 to 66.6 mD at the end of the matrix regime (denoted by  $k_{end, m}$ ). It is observed that at the end of the test (i.e. when the flow rate is decreased after fracturing), the overall permeability is  $k_{unload}$  87.4 mD. Comparing the permeability at the end of the matrix regime  $k_{end, m}$ , and at the end of the test  $k_{unload}$  permits to assess that the gain of permeability due to fracturing is of 31%.

## 5.2 Observations of the specimen after fracturing.

The specimen was imaged before injection (Scan 1) and after fracturing (Scan 2). **Fig. 12a** presents a view of X-ray CT scanning of the specimen. The voxels are cubic with a size of 29  $\mu\text{m}$ . The 3D images are reconstructed using X-Act software (RX-Solutions, Chavanod, France). Some typical horizontal cuts of the X-ray CT images are presented in **Fig. 12**. Compared to the initial state (Scan 1), the images of the fractured specimen (Scan 2) show some darker bands developed around the injection tube which indicate the localized fractures.

In order to visualize the 3D shape of the fractures, image processing was applied in the X-ray CT images which consists of three principal steps. Firstly, the filtering was applied to reduce the noise of the images while keeping the contours between different phases. Then, thresholding was performed to obtain the binary image that distinguishes between the fracture and the surrounding medium. Finally, the volume rendering was made to display a three-dimensional (3D) view of the fracture along the tube by using the ImageJ 3D Viewer plugin (Schmid et al., 2010). This process was carried out on a volume extracted at the middle of the specimen from  $H = 10$  to  $H = 12$  cm which is delimited by the window in dashed line presented in **Fig. 12e**. Multiple small fractures were observed in several directions around the injection tube which can be related to the pressure drops during the water injection phase (**Fig. 13**). Similar fractures geometry has been also observed in tests performed by Bohloli and de Pater (2006)

**Fig. 14** presents some typical photos of the specimen during excavation after the test. Some small fractures were observed along the injection tube (darker blue) which are fairly consistent with those observed in the X-ray CT image. The length of these fractures varies from few millimeters up to one centimeter with an opening of about one millimeter (i.e. 5 grains size).

Moreover, in order to identify the change of the granular structure, a typical horizontal cross-section at  $H = 8$  cm was observed using optical Microscope Leica M80 (**Fig. 15a**). The fracture is clearly identified as a darker blue zone visible to the naked eye (**Fig. 15Fig. 14b**). As the silica gel is a transparent gel with nano-particle size between 7 and 22 nm, it allows to observe the sand structure inside the gel. We can clearly observe that the fracture presents fewer C10 particles and more porous space as compared to the surrounding medium (**Fig. 15c&d**). It can be seen that during fracturing when the injection pressure and drag force locally become greater than a critical threshold, the dilation of the sand matrix occurred in some localized zones around the injection point where the injection pressure was highest. This phenomenon is attributed to a higher pore network within these zones leading to the detachment of C10 particles from the sand matrix and transport by the fluid flow. Therefore, a preferential path ('pseudo-crack') of high porosity is created favoring the injectivity. Thus, these pseudo-cracks appear as zones of higher porosity, higher pore size, in which finer particles have been mobilized

343 and transported by the fluid. These observations highlight the main differences between fracturing of an  
344 unconsolidated medium and fracturing of quasi-brittle materials. Fracturing of quasi-brittle materials is  
345 the result of two subsequent processes: localization of damage corresponding to crack initiation and  
346 crack propagation controlled by the stress intensity factor at the crack tip. Fracturing of unconsolidated  
347 medium is controlled not only by the stress state (that controls strain localization and dilatancy inside  
348 the specimen), but also by the flow rate (which controls the fine particles transport and deposition).

## 349 6. Sensitivity analysis

350 To highlight the key factors controlling the initiation of the fracture and the fracturing mode, a series  
351 of tests was carried out. The characteristics of these tests are summarized in **Table 5**. The effects of  
352 various parameters such as stress conditions (confining pressure, stress ratio), permeability and flow rate  
353 on the critical fracturing pressure, the increase of the overall permeability as well as the fracture shape  
354 are explored.

### 355 6.1 Test repeatability and influence of the flow rate during the fracturing regime

356 Test P7 was performed under the same characteristics as the reference test P1. The injection protocol in  
357 the matrix regime is also similar to that of test P1 with the increase of the flow rate by steps of 0.033  
358 l/min. However, in the fracturing regime, test P7 was carried out with 6 steps, instead of 4 steps as for  
359 test P1, to study the impact of the increase of the flow rate on the fracturing propagation within the  
360 specimen which is one of the most important parameters that the reservoir engineers can control for  
361 maintaining injectivity during the PWRI operation (Ochi et al., 2014). The first injection part of this test  
362 allows to evaluate the test repeatability in the radial injection cell in terms of the critical fracturing  
363 pressure. The detailed results of test P7 are presented in **Fig. 16a**. The first pressure drop was identified  
364 at a flow rate  $Q_{frac}$  of 0.85 l/min (Figure 3.20b) and the corresponding fracturing pressure  $P_{frac}$  is 462 kPa  
365 ( $2.3 \sigma_h$ ). This critical pressure is about 5% smaller than the critical value obtained for test P1, confirming  
366 a very good test repeatability in the radial injection cell. The flow rate was then increased with five more  
367 steps up to 1.03 l/min before stop pumping (**Fig. 16b**). Significant pressure drops were identified in the  
368 frac-regime. **Fig. 16c&d** present the observation of different zones by optical microscopy. The results  
369 are similar to those observed for the reference test: less C10 fine particles and larger pore size are  
370 observed inside the fracture as compared to the surrounding medium.

371 **Fig. 17** presents a comparison between tests P1 and P7. A fairly good consistency in terms of pressure  
372 – flow rate curve can be observed in the matrix flow regime (before the first pressure drop) (**Fig. 17a**).  
373 In the fracturing regime, we can observe that increasing further the flow rate results in further  
374 propagation and enlargement of the fracture (**Fig. 17c&d**). The fracture morphology in specimen P7 is  
375 characterized by vertical fractures propagating radially from the tube, with the longest even reaching the  
376 specimen boundary. This observation is in accordance with a higher increase of the overall permeability  
377 of test P7 as compared to P1 (**Fig. 17b**).

378 For the radial injection cell tests, the injection of 4 steps in the fracturing regime is a suitable protocol  
379 when performing the parametric study in this setup to avoid the boundary effect as observed in specimen  
380 P7.

### 381 6.2 Effect of stress conditions

#### 382 6.2.1 Confining pressure

383 The confining pressure is one of the most important parameters controlling the fracturing process,  
384 therefore, many studies have been performed to investigate the effect of this parameter on hydraulic

385 fracturing in unconsolidated sands (Bohlooli and de Pater, 2006; Golovin et al., 2010; Hurt, 2012). To  
386 investigate this effect, six tests have been performed with different values of the confining pressure (120,  
387 150, 200 and 350 kPa) and different stress ratios  $K_0 = \sigma_h/\sigma_v$  (0.33, 0.4 and 0.5). **Fig. 18a** presents the  
388 injection results in the case of  $K_0 = 0.33$ . Tests P2 and P4 have been performed with a confining pressure  
389 of 150 kPa and 200 kPa, respectively. We observe that a higher confining pressure leads to a higher  
390 critical fracturing pressure. The first pressure drop  $P_{frac}$  in test P2 (150 kPa of confining pressure) is 360  
391 kPa and 435 kPa in test P4 (200 kPa of confining pressure). However, the ratio of the fracturing pressure  
392 over the confining pressure is very close for both tests (2.4 for test P2 and 2.2 for test P4).

393 **Fig. 18b** shows that a higher increase of the overall permeability is observed at lower confining  
394 pressure. As the specimen is manually compacted with the mixture of sand and fine particles, the initial  
395 overall permeability may be slightly different depending on the compaction process, the homogeneity  
396 of the mixture, the pore network, etc... During the disassembling phase of the experiment, test P2 with  
397 lower confining pressure presents longer fractures as compared to test P4 (**Fig. 19**). The main fracturing  
398 pattern observed in these tests is the non-symmetric bi-wing fractures propagating along the injection  
399 tube. Similar results are obtained for  $K_0 = 0.4$  (**Fig. 18c&d**) and  $K_0 = 0.5$  (**Fig. 18e&f**). **Fig. 20** presents  
400 a synthesis of the normalized fracturing pressure ( $P_{frac}/\sigma_h$ ) under different stress conditions. The mean  
401 value of this quantity is 2.35 and the standard deviation is 0.1. The standard deviation is about 4% of the  
402 mean value, showing that the normalized fracturing pressure is not affected by the change of the stress  
403 conditions within the range tested here. Note that some authors have found that this ratio can  
404 significantly vary in the range of 3 to 20 depending on experimental setups, injection protocols as well  
405 as the rheology of the injection fluid (Bohlooli and de Pater, 2006; Zhou et al., 2010; Hurt, 2012).

#### 406 6.2.2 Stress ratio coefficient $K_0$

407 To investigate the effect of  $K_0$  on the fracturing process, three tests with different values of the axial  
408 stress values  $\sigma_v$  (400, 500, 600 kPa) while keeping the same confining pressure constant (200 kPa) have  
409 been performed. The results are shown in **Fig. 21**, and show that the stress ratio coefficient has a  
410 negligible effect on the fracturing pressure  $P_{frac}$ . A slight difference of this ratio is within the repeatability  
411 of the test. Test P4 with a higher axial stress presents the smallest fracturing pressure and smallest  
412 increase of the overall permeability.

#### 413 6.3 Effect of the initial permeability

414 Different scenarios of the extension and the nature of the clogged area due to PWRI can lead to  
415 different values of the permeability around the injection point. To investigate the effect of the  
416 permeability of the specimen, test P8 with a specimen containing only 19% of C10 fines (as compared  
417 to 22% for the reference test) was performed. The stress conditions are similar to those of P6 ( $\sigma_h = 120$   
418 kPa and  $\sigma_v = 300$  kPa). The injection rate is gradually increased by step of 0.066 l/min (instead of 0.033  
419 l/min for the other tests with 22% C10), in order to have the same pressure steps in the specimen during  
420 each corresponding flow rate step. **Fig. 22a&b** present the results in the matrix regime of tests P6 and  
421 P8, respectively. Each increase of the flow rate corresponds to an increase of about 20 kPa of the  
422 injection pressure for both tests. **Fig. 22c** shows a comparison of the two tests in terms of pressure –  
423 flow rate curves. The critical fracturing pressures  $P_{frac}$  are very close (about 2.4 to 2.5 times the confining  
424 pressure). A higher increase of the permeability is observed in the case of lower concentration of C10  
425 fines (higher initial permeability). However, it should be noted that test P8 was performed with higher  
426 increase of each flow rate steps which may also contribute to the higher increase of the permeability.  
427 The observation of the fracture shape during excavation allows to confirm the change of the overall  
428 permeability during injection (**Fig. 22e&f**). Higher increase of the permeability after fracturing is  
429 associated to longer and wider fractures.

430 **7. Conclusions**

431 A new experimental setup has been developed which allows to simulate the radial injection  
432 configuration of injection wells for investigating fracturing mechanisms in unconsolidated sand  
433 reservoirs. This device makes possible observations of the entire specimen by X-ray CT while keeping  
434 the structure intact before and after fracturing. Specimens are prepared as a mixture of silica sand and  
435 fine silica particles to simulate the internal cake formed during PRWI operations.

436 Typical injection results show that the fracturing occurs at a critical injection pressure of about 2.4  
437 times the confining pressure. After fracturing, the overall permeability of the specimen increases. The  
438 injection of a silica gel permits to freeze the structure of the fractured specimen for performing post-  
439 mortem observations of the specimen. X-ray CT allows to obtain 3D images of the fractures formed  
440 along the injection tube and the fractures observed from X-ray CT coincide with those observed during  
441 disassembling and excavation of the specimen. These vertical fractures are short with multiple small  
442 branches propagating radially from injection tube which can be associated with the pressure drops  
443 identified during water injection phase. Optical microscopic observations of the specimen after the tests  
444 have permitted to identify the dominant fracturing mechanisms in the sand specimen. The pseudo-cracks  
445 appear as zones of higher porosity and higher pore size which result from the formation of localized  
446 dilation shear bands in the sand matrix and the subsequent transport of finer particles.

447 The sensitivity analysis shows that the critical fracturing pressure is mainly controlled by the  
448 confining pressure (radial stress) and does not change significantly with the stress ratio  $K_0$ . Increase of  
449 confining pressure leads to the proportional increase in critical fracturing pressure, shorter fractures as  
450 well as smaller increase of the overall permeability. For all the tests performed, the mean of the  
451 normalized fracturing pressure is about  $2.35 \pm 0.1$ . Further increase the flow rate in the fracturing regime  
452 leads to extend the fractures, and consequently, contributes to higher gain of the overall permeability.  
453 Changing the concentration of C10 fines in the specimen permits to change the initial permeability of  
454 the specimen. However, no significant effect of the initial permeability on the critical fracturing pressure  
455 has been observed. For unconsolidated sand specimens, the fracturing pattern is difficult to predict with  
456 the growth of multiple or unsymmetrical bi-wing fractures as observed in this work. Future work will  
457 extend this research to investigate the effect of the injection scenario, of the viscosity of fluid, and the  
458 presence of suspended particles in the injected fluid on the fracturing response of the sand formations.

459

460

461 **Declaration of competing interest**

462 The authors declare no competing financial interest.

463

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469

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575 **List of Symbols**

576

<b>Symbol</b>	<b>Units</b>	<b>Definition</b>
$I_{D\ NE34}$		Density index of the NE34 sand matrix
$k$	Darcy	Intrinsic permeability
$K_0$		Stress ratio coefficient
$p$	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
$\Delta P_s$	kPa	Pressure loss in the specimen
$\sigma_h$	kPa	Confining pressure
$\sigma_v$	kPa	Axial stress

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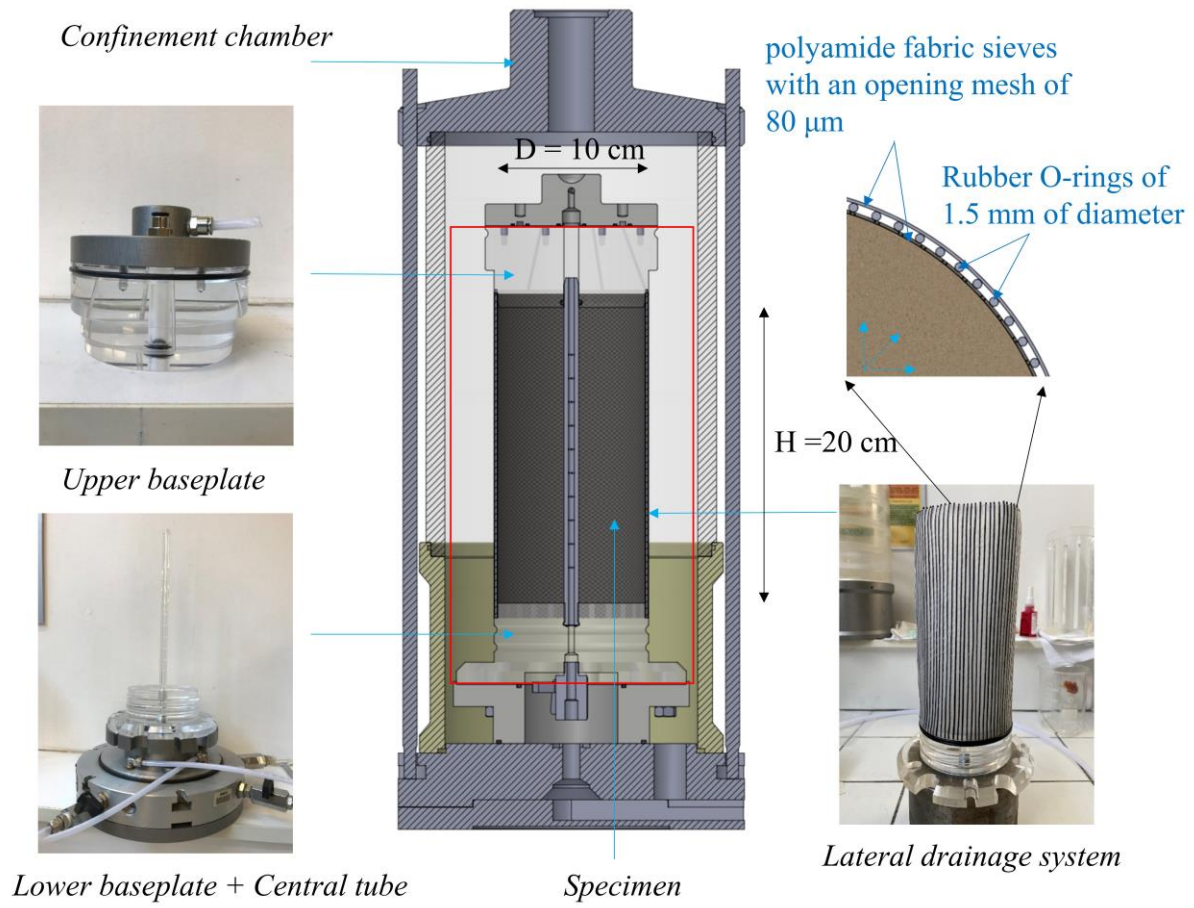
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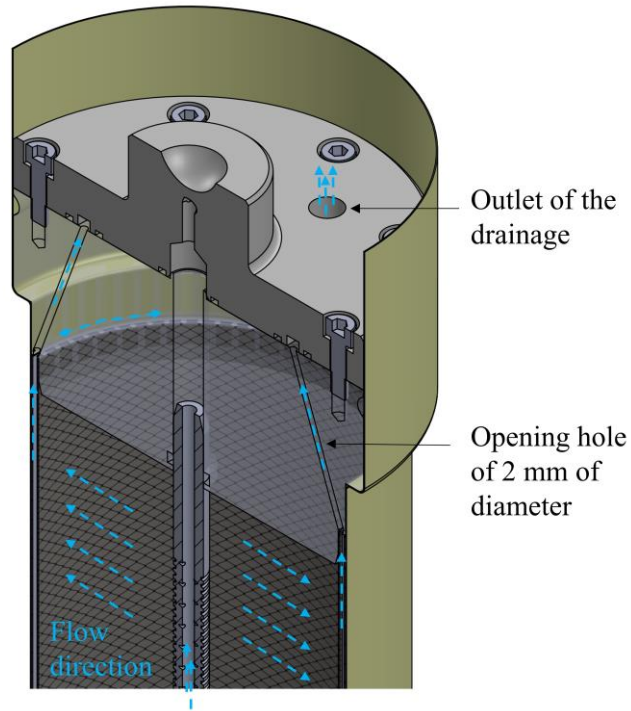
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**Fig. 1.** 2D cross section of the radial injection cell and its corresponding components.

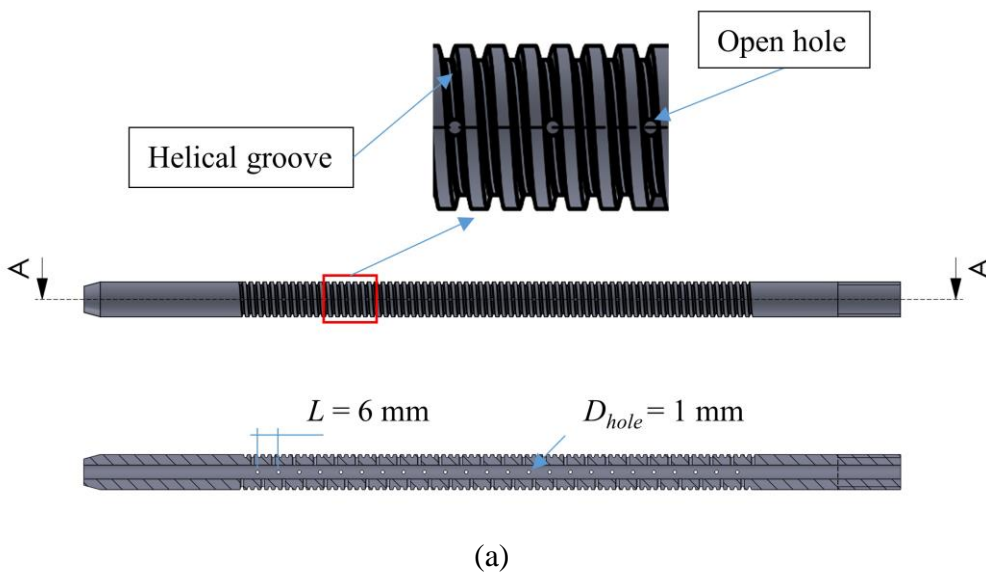


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**Fig. 2.** 3D schematic cross-section representing the flow direction within the radial injection cell.

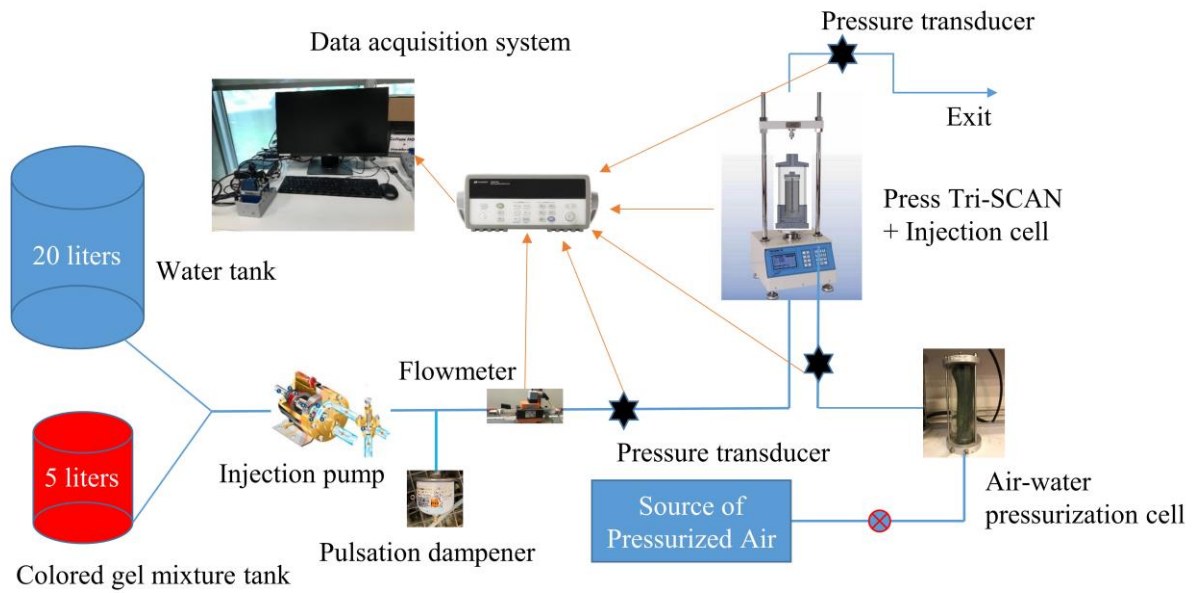
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**Fig. 3.** (a) configuration of injection tube; (b) view of the tube covered with polyamide fabric sieves.

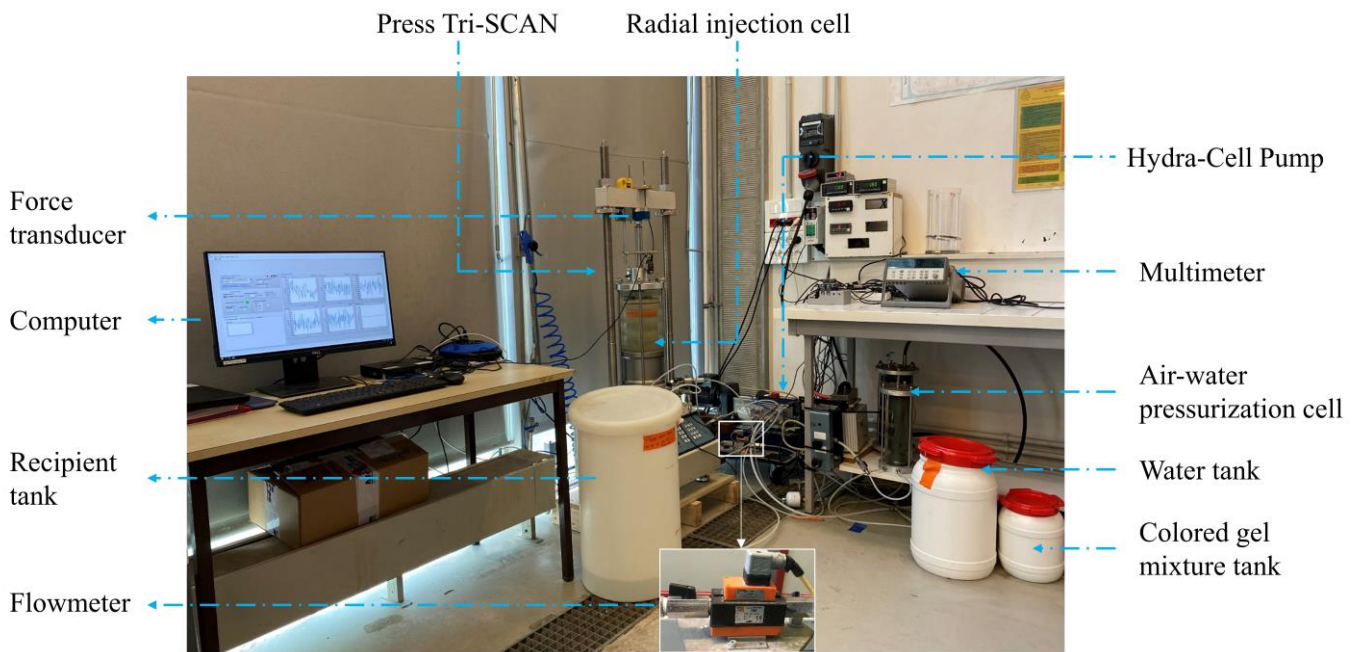


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**Fig. 4.** Functional scheme of the radial injection cell setup.

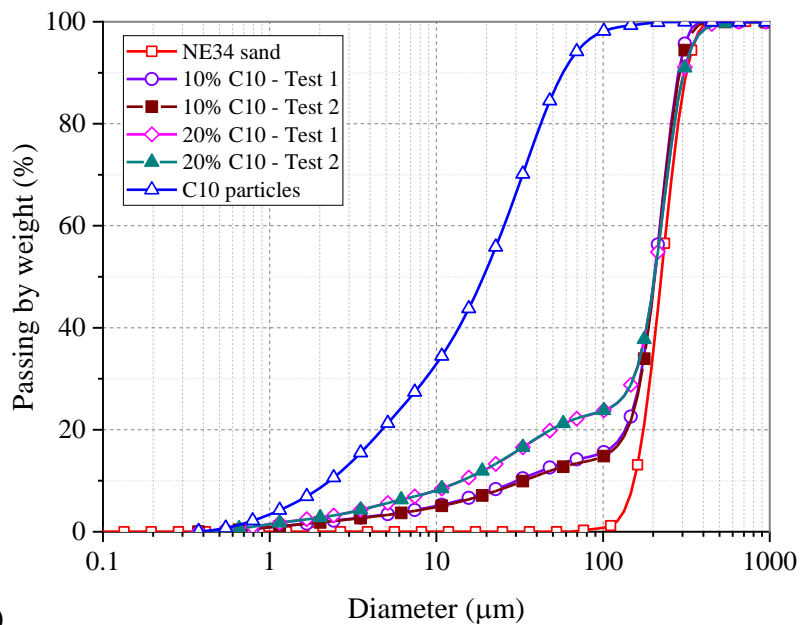
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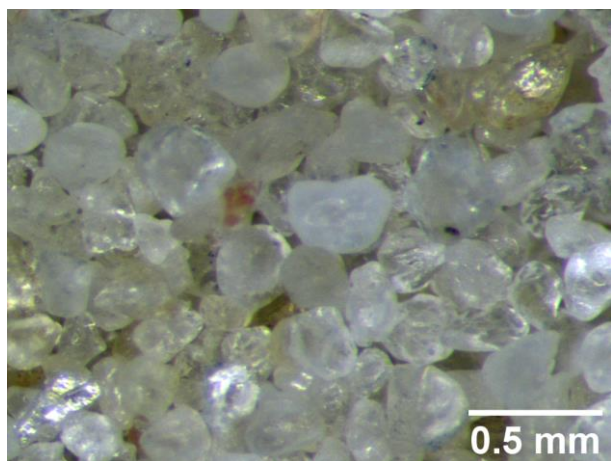
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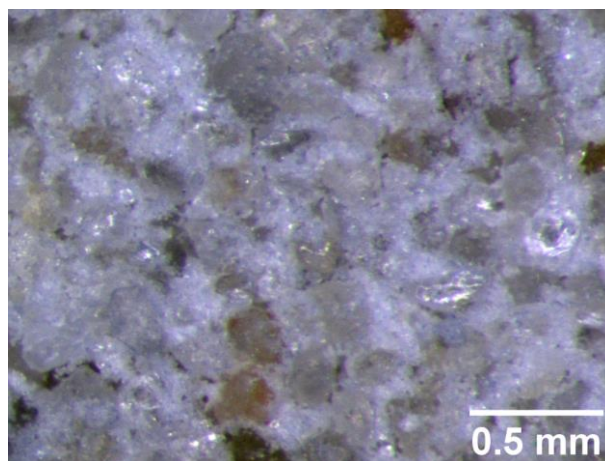
**Fig. 5.** General view of the radial injection cell setup.



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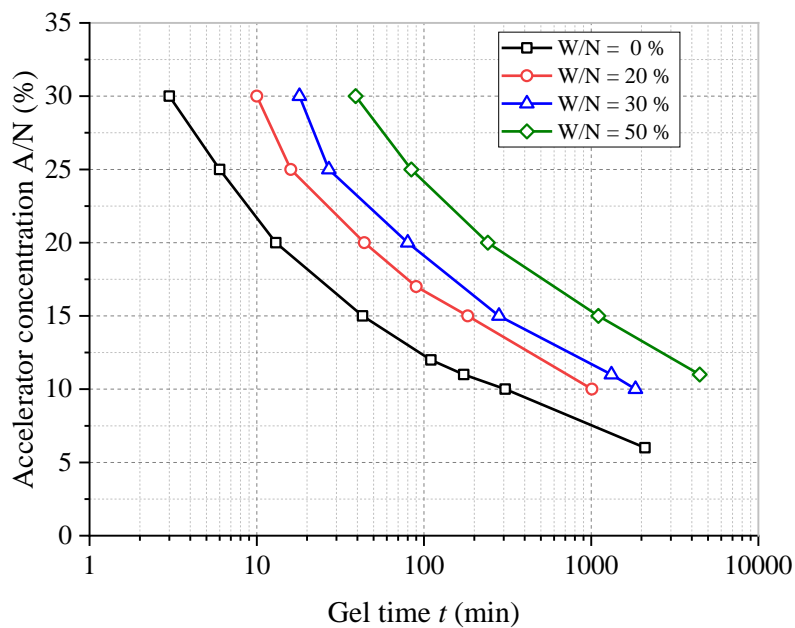


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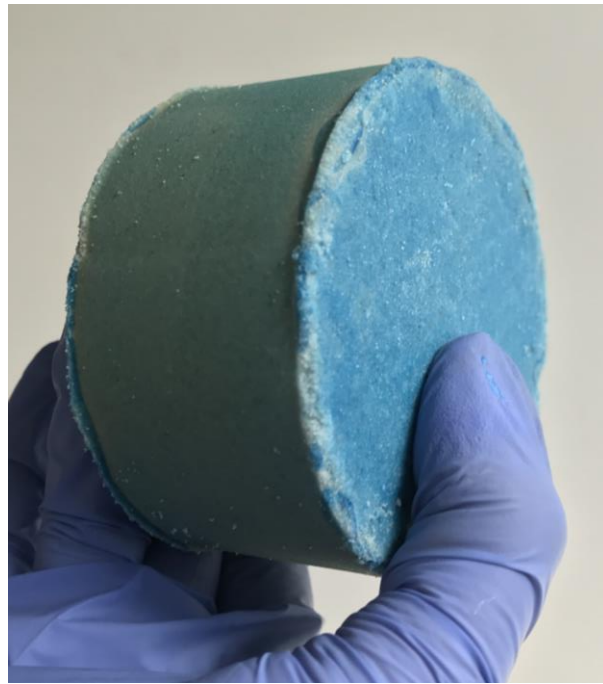


(c)

**Fig. 6.** Tested material: (a) grain size distribution; (b), (c) optical microscopy views of pure NE34 sand and of the reference mixture (NE34 sand + 22% C10), respectively.

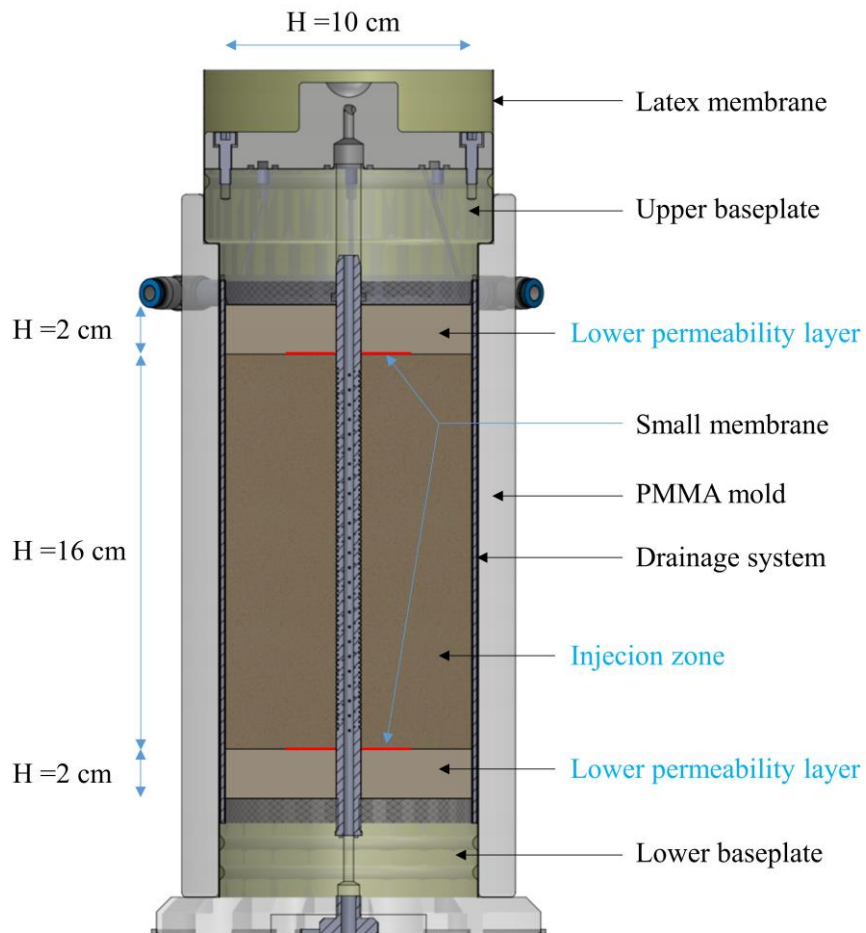


(a)

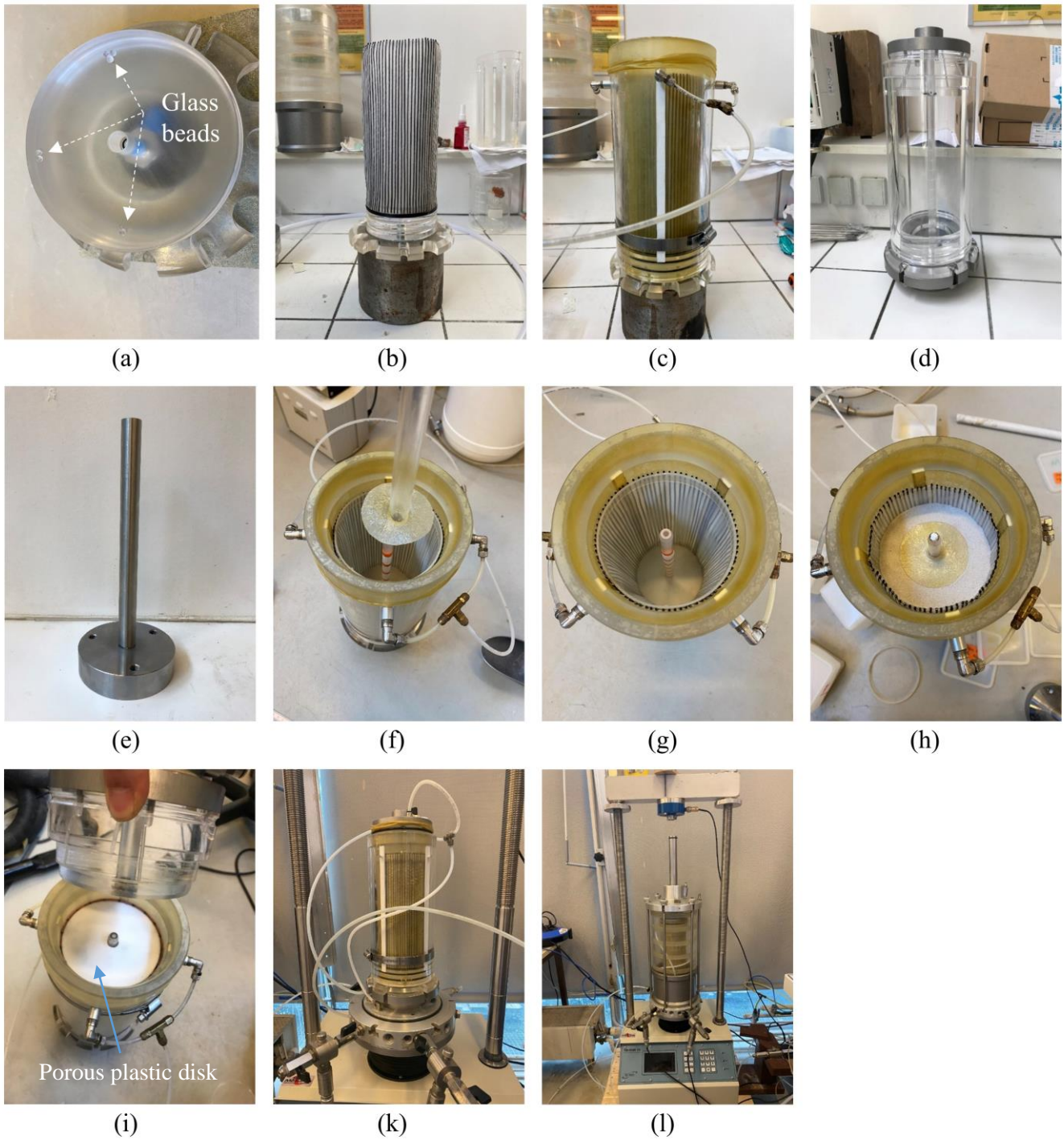


(b)

**Fig. 7.** Colored gel solution: (a) gel time of MasterRoc MP320 with different accelerator ratios and dilution ratios; (b) solidified sand specimen with the mixture of MasterRoc MP320 and Basacid® Blue 762.

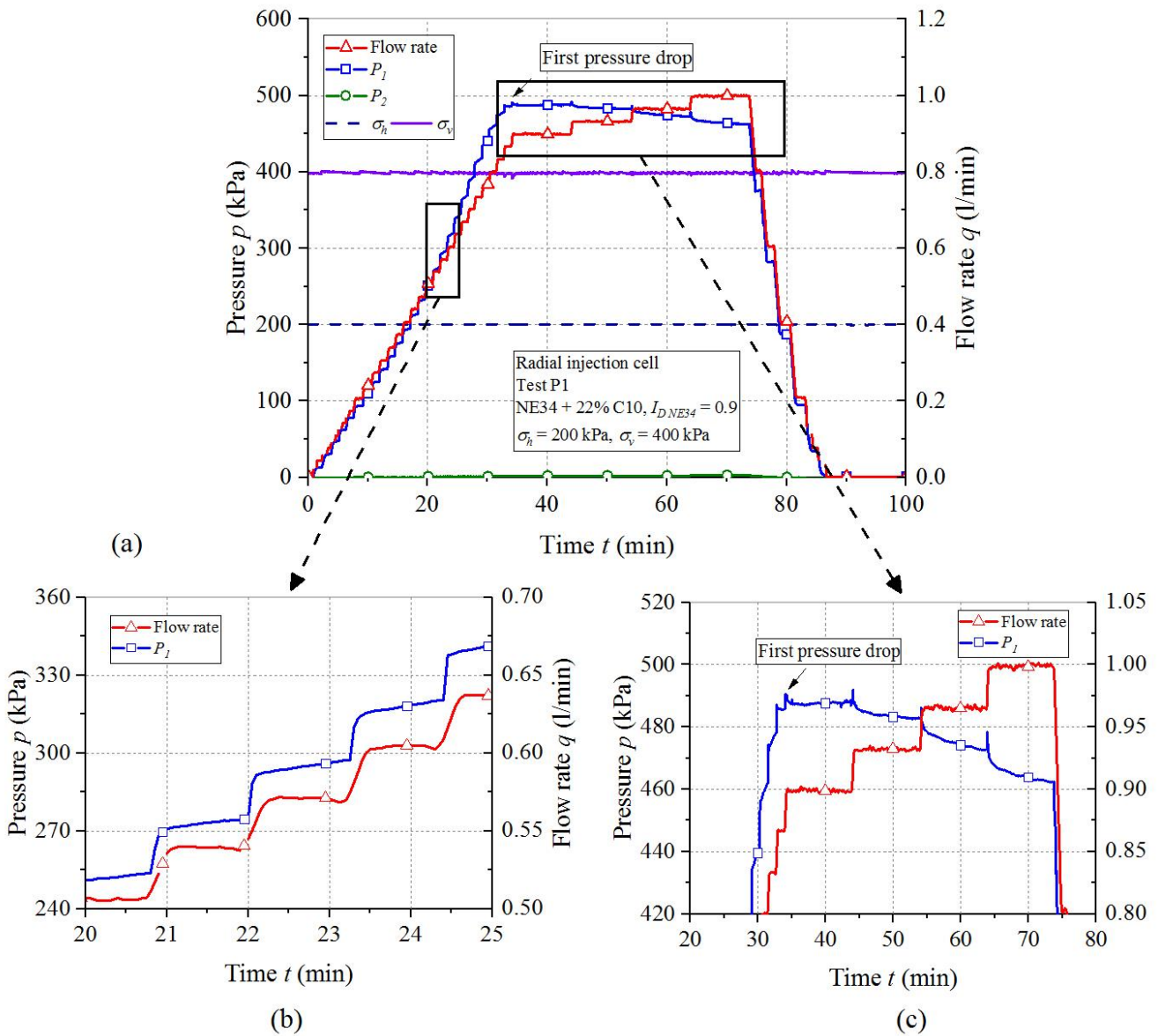


**Fig. 8.** Configuration of the specimen preparation.



**Fig. 9.** Fabrication of the specimen and assembly of the injection cell: (a) glass beads glued to the lower plate; (b) lateral drainage system and injection tube setup; (c) pressing the membrane onto the mold; (d) PMMA mold; (e) groomer; (f) setting up a small latex membrane; (g) compaction of the injection zone; (h) second small membrane; (i) upper base plate; (k) fixing the cell to the Press Tri-SCAN; (l) saturation.

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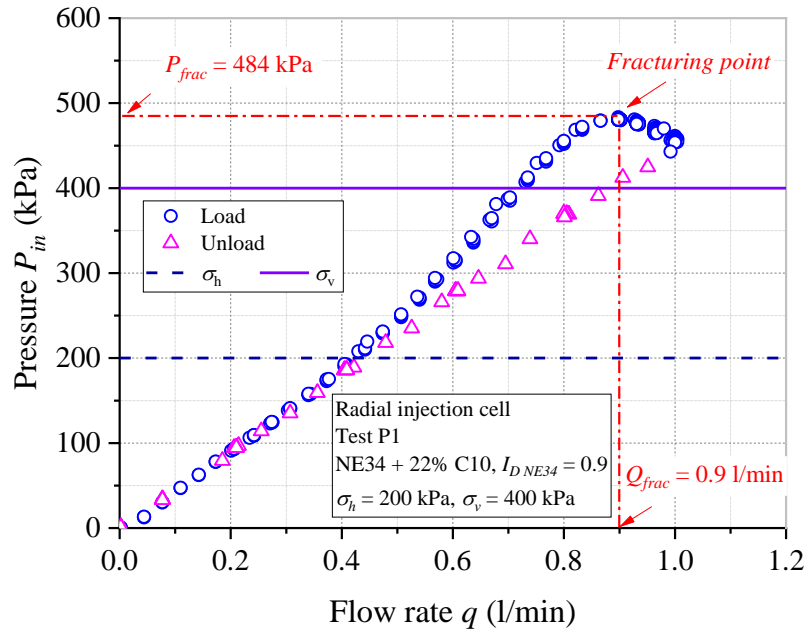
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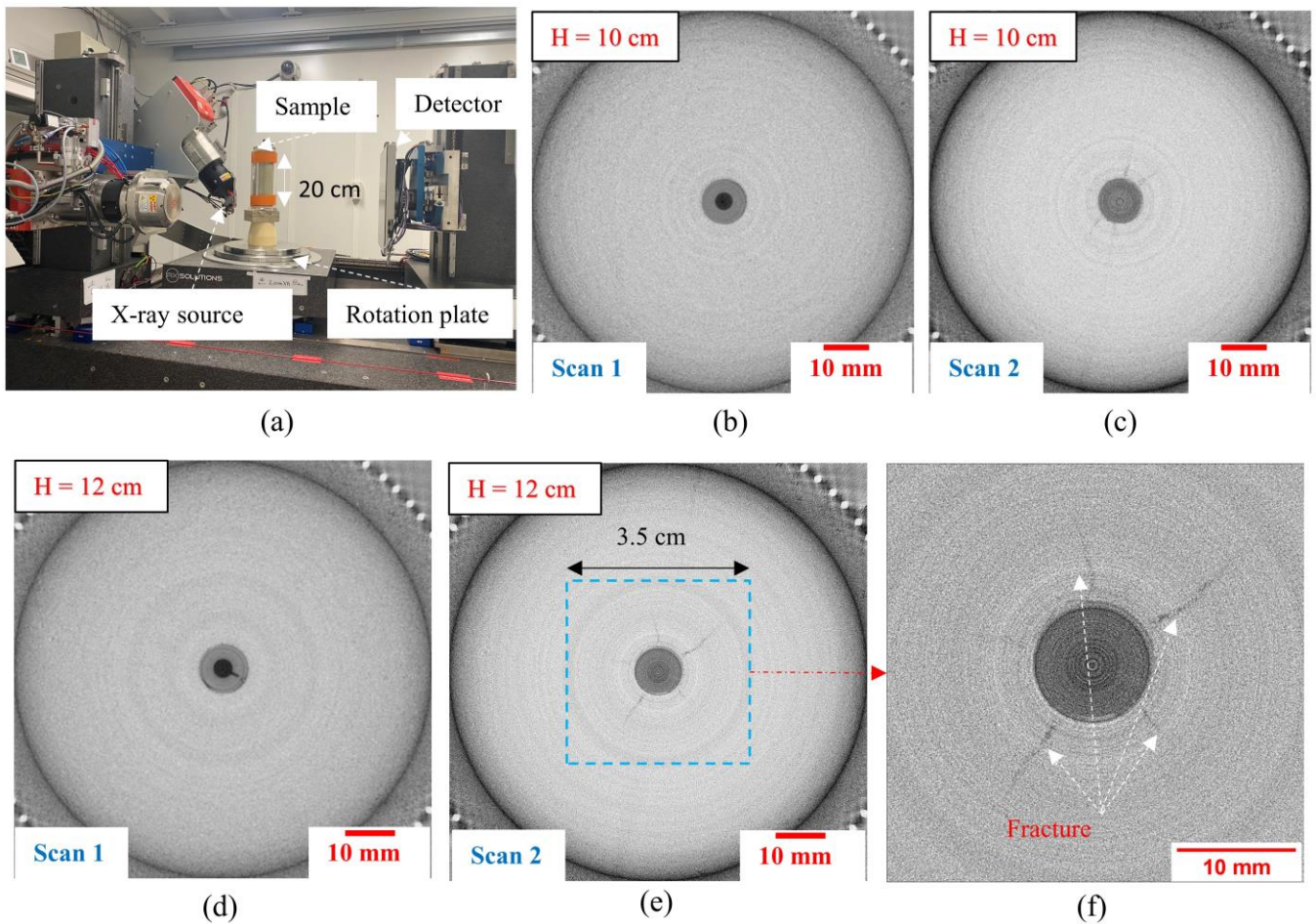
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**Fig. 10.** Results of the reference test P1: (a) evolution of pressure and flow rate versus time during water injection phase; (b) zoom between 20 to 25 minutes showing the injection pressure during matrix regime; (c) zoom between 30 to 80 minutes showing significant pressure drops during fracturing regime.

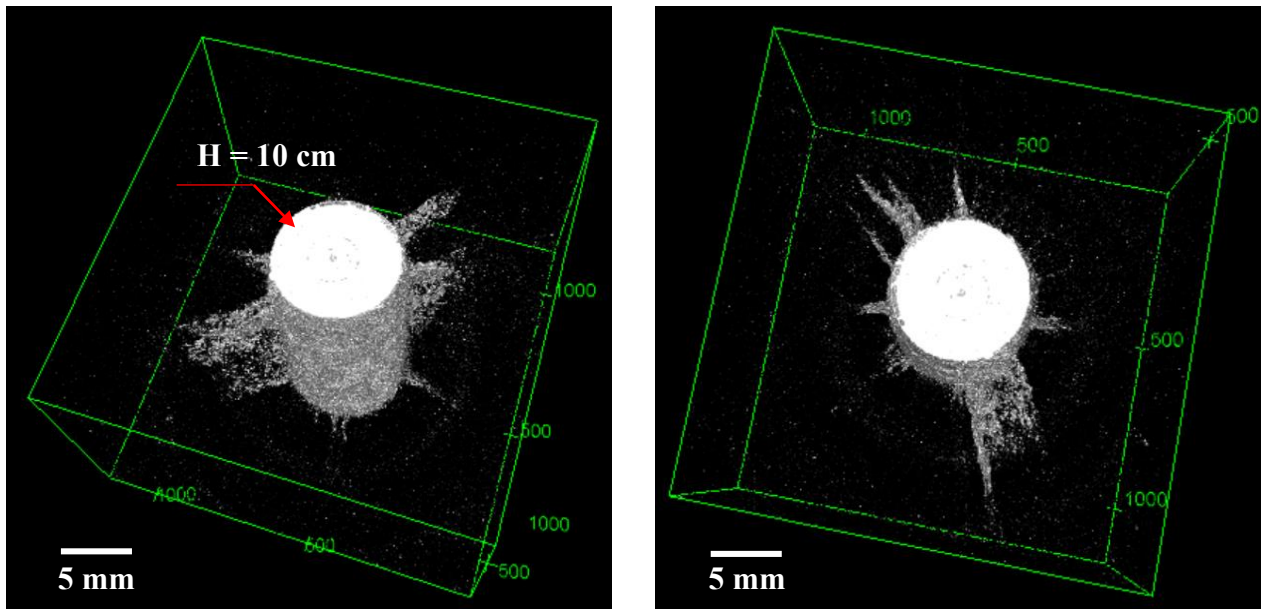


622  
623 **Fig. 11.** Evolution of injection pressure versus flow rate.



624  
625 **Fig. 12.** Typical X-Ray CT images at different heights: (a) Global view of the setting; (b) and (c)  
626 cross-sections of the specimen before (scan 1) and after fracturing (scan 2) at H = 10 cm, (d) and (e)  
627 cross-sections of the specimen before (scan 1) and after fracturing (scan 2) at H = 12 cm; (f) magnified  
628 zone containing the fractures over which the image treatment process is applied. Voxel size: 29  $\mu\text{m}$ .

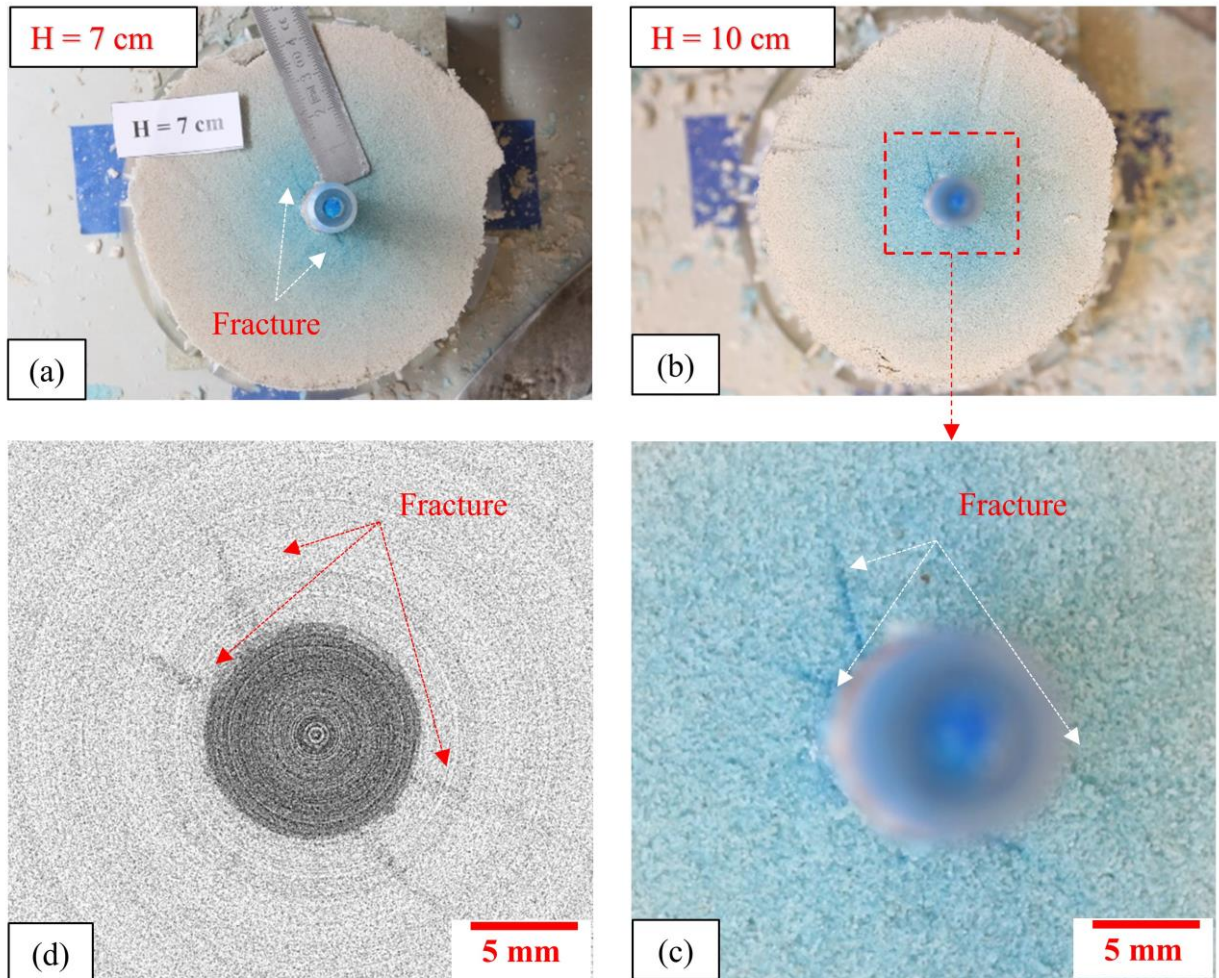




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**Fig. 13.** 3D views of the fracture developed along the injection tube from  $H = 10$  to  $H = 12$  cm.



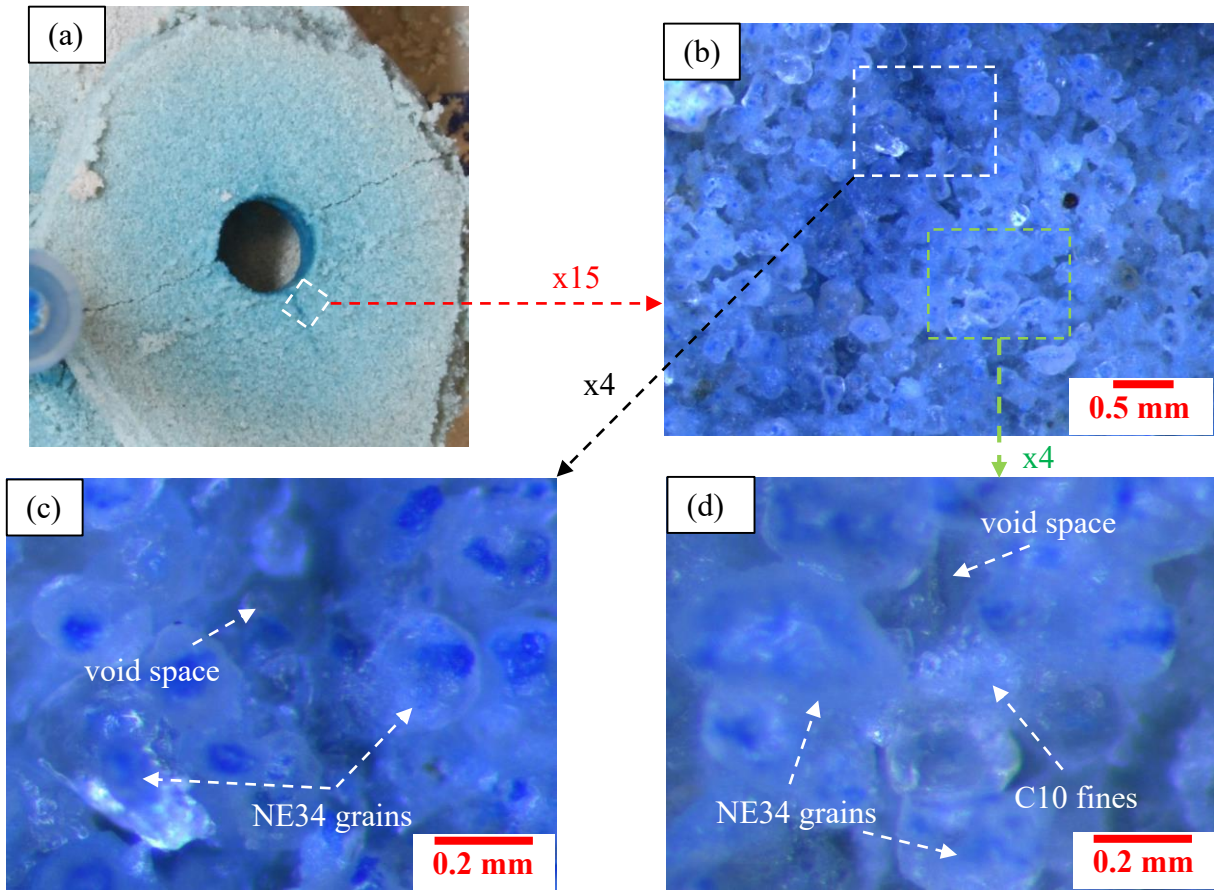
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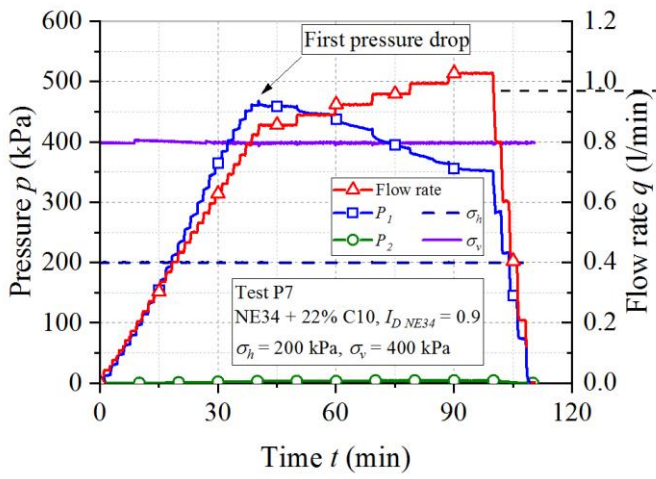
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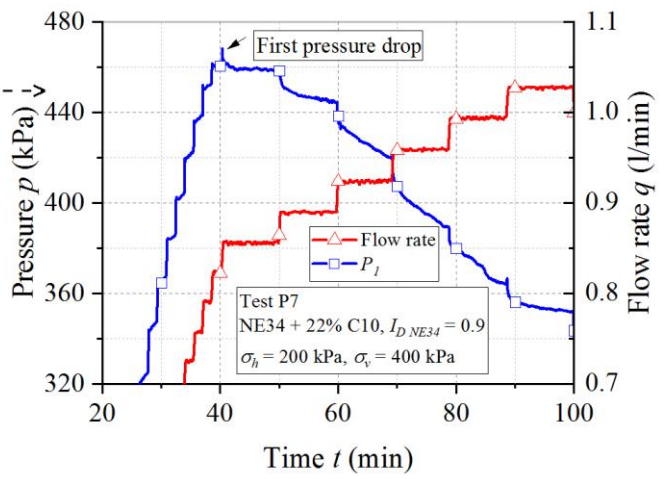
**Fig. 14.** Photos of the horizontal cross-sections corresponding to different depths of excavation: (a) at  $H = 7$  cm; (b) at  $H = 10$  cm; (c) magnified zone around the tube at  $H = 10$  cm and (d) its observation from X-ray CT.



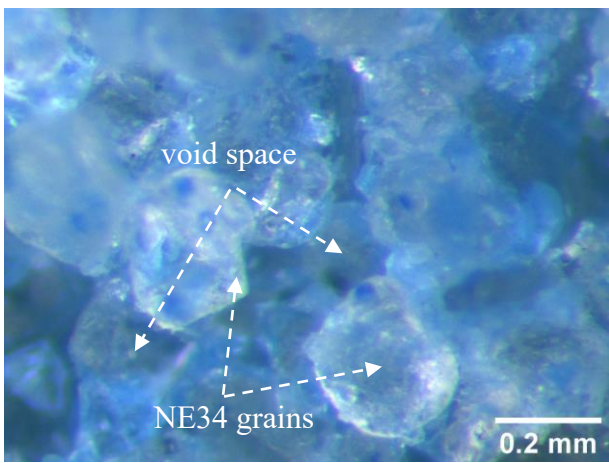
636 **Fig. 15.** Optical microscope observation of a typical transversal cross-section at different zones: (a)  
 637 typical cross-section of the specimen; (b) magnified zone containing the fracture; (c)  
 638 magnified zone inside the fracture; (d) magnified zone at the surrounding medium.



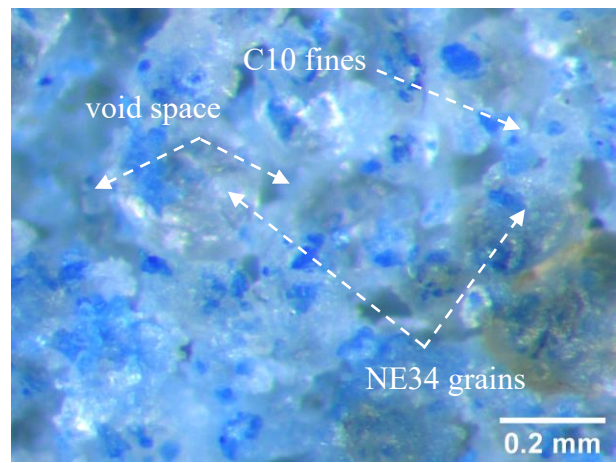
(a)



(b)

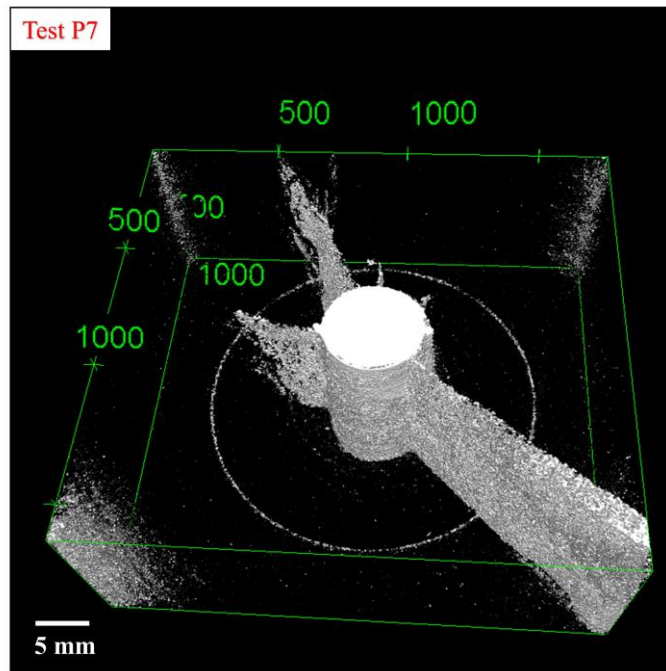
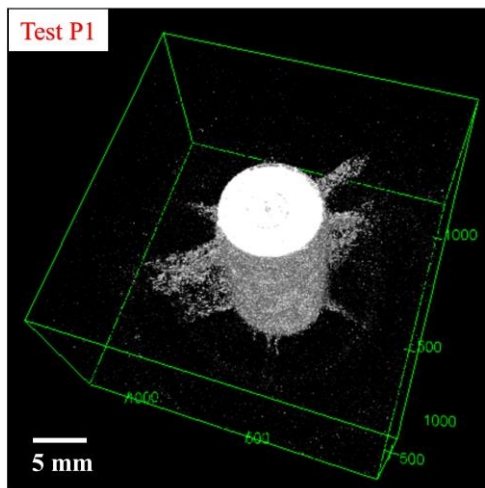
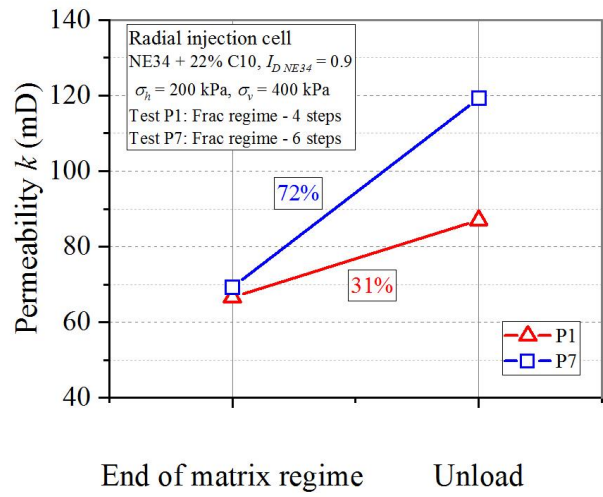
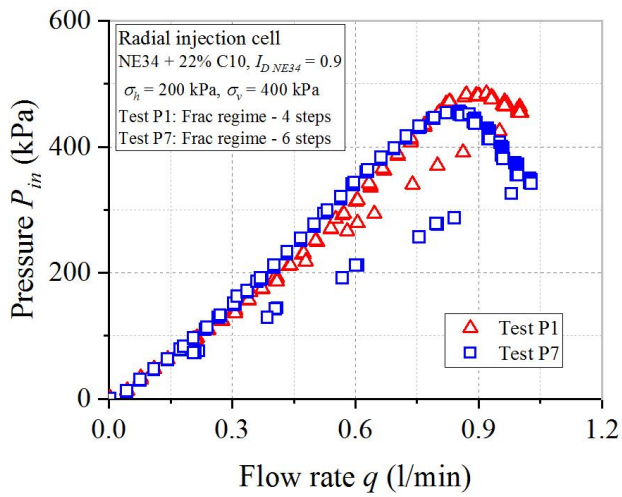


(c)



(d)

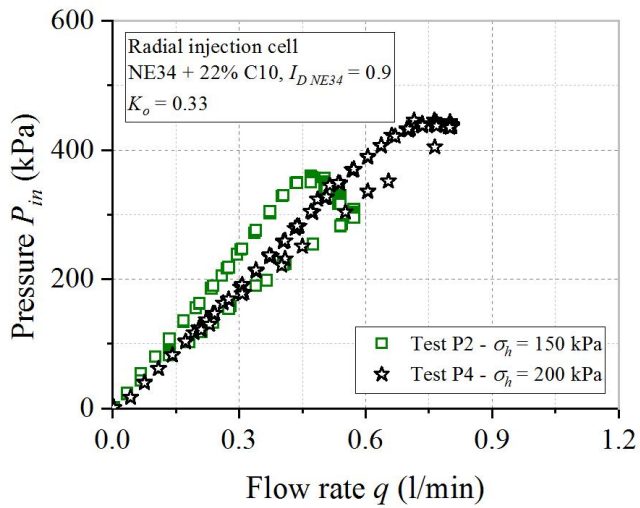
**Fig. 16.** Test P7: (a), (b) pressure - flow rate - time curves; (c) magnified zone inside the fracture; (d) magnified zone in the surrounding medium.



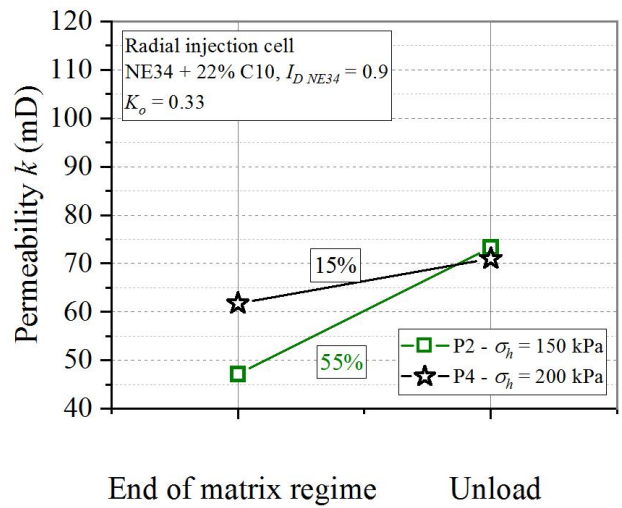
(c)

(d)

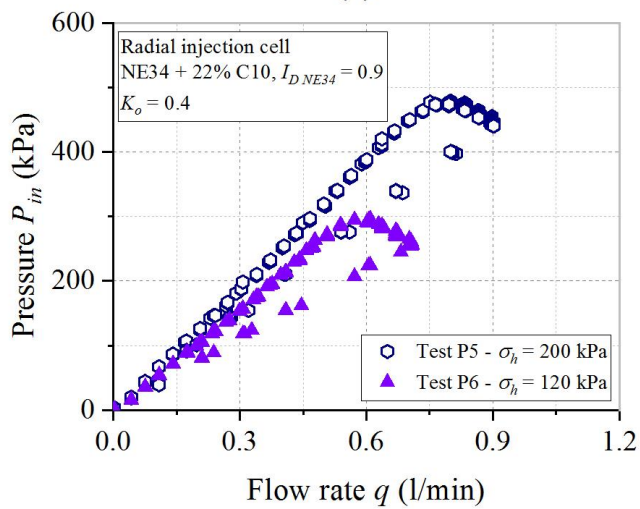
**Fig. 17.** Effect of flow rate: (a) pressure vs flow rate curves; (b) increase of the overall permeability; (c), (d) 3D views of the fracturing pattern developed along the injection tube from  $H = 10$  to  $H = 12$  cm for test P1 and P7, respectively.



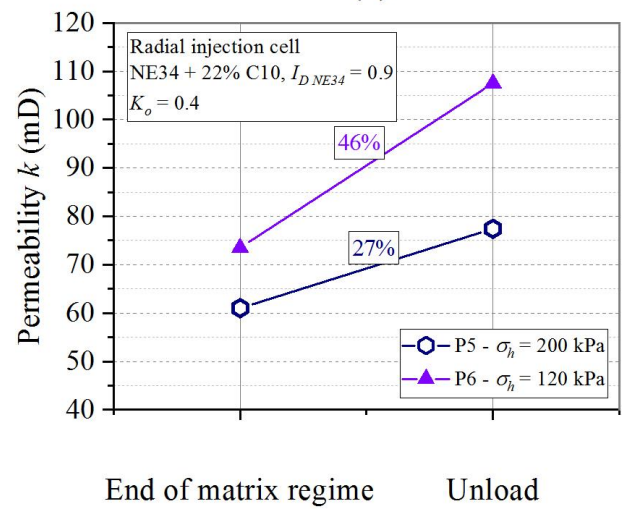
(a)



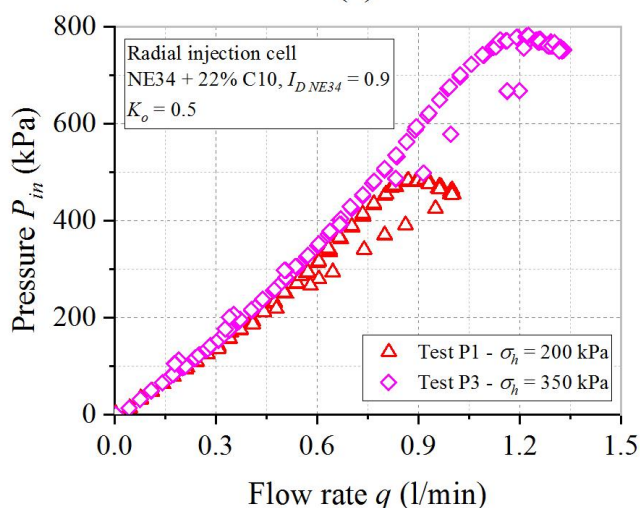
(b)



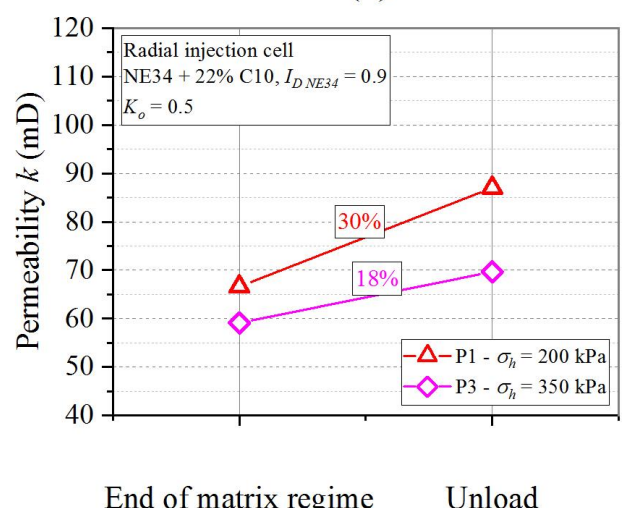
(c)



(d)



(e)



(f)

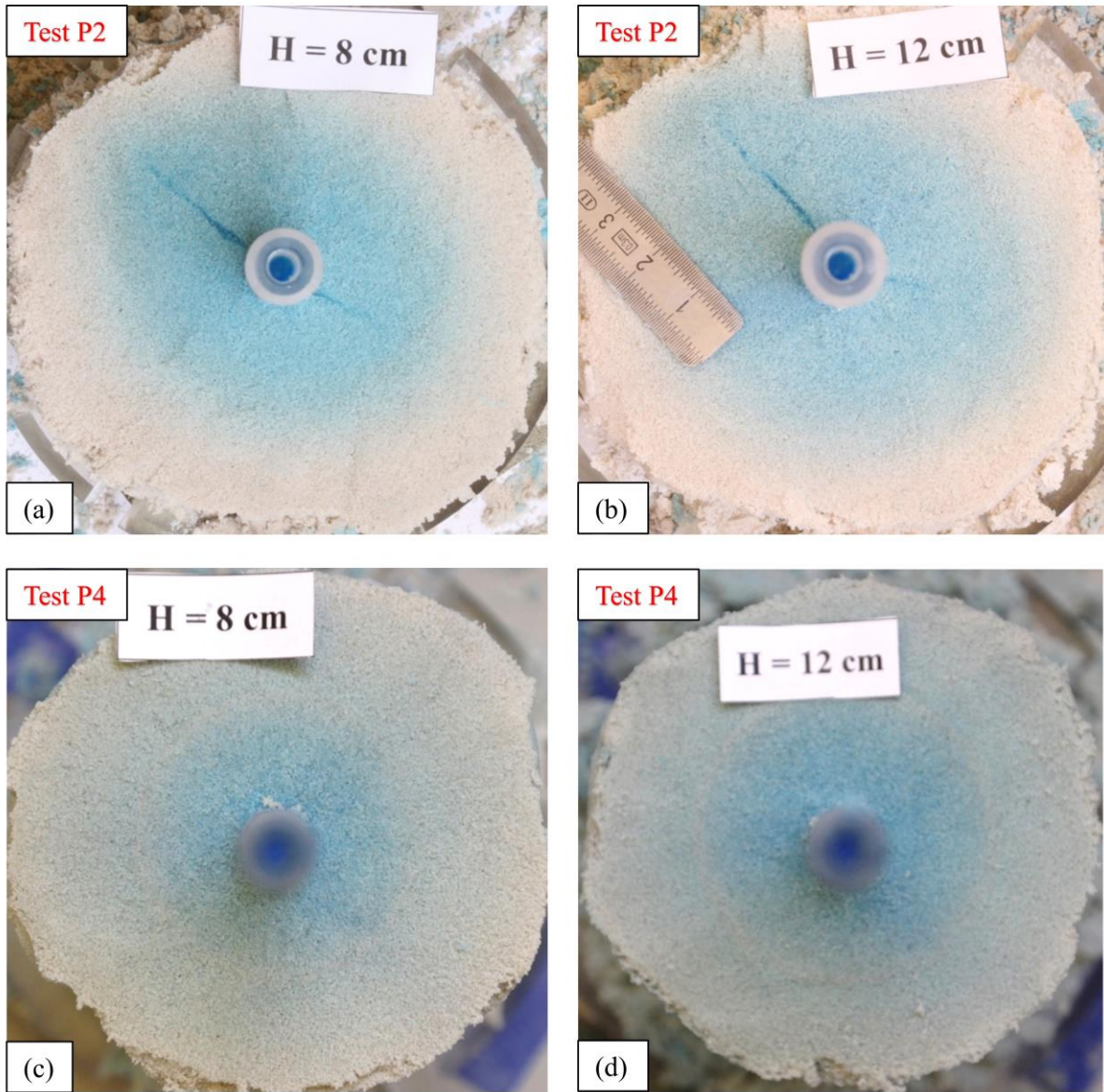
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**Fig. 18.** Effect of confining pressure on the pressure vs flow rate curves and the increase of the overall permeability in the different cases of  $K_o$ : (a), (b)  $K_o = 0.33$ ; (c), (d)  $K_o = 0.4$ ; (e), (f)  $K_o = 0.5$ .

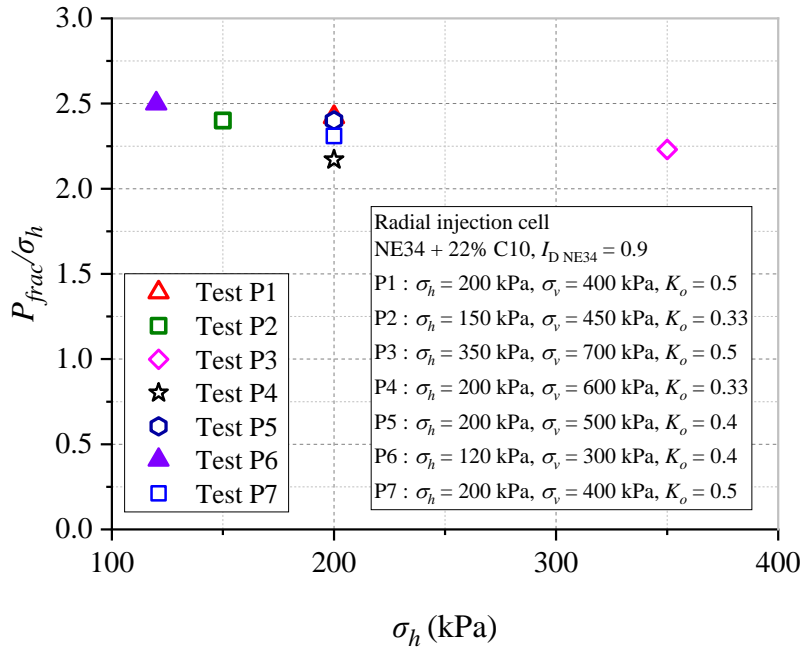


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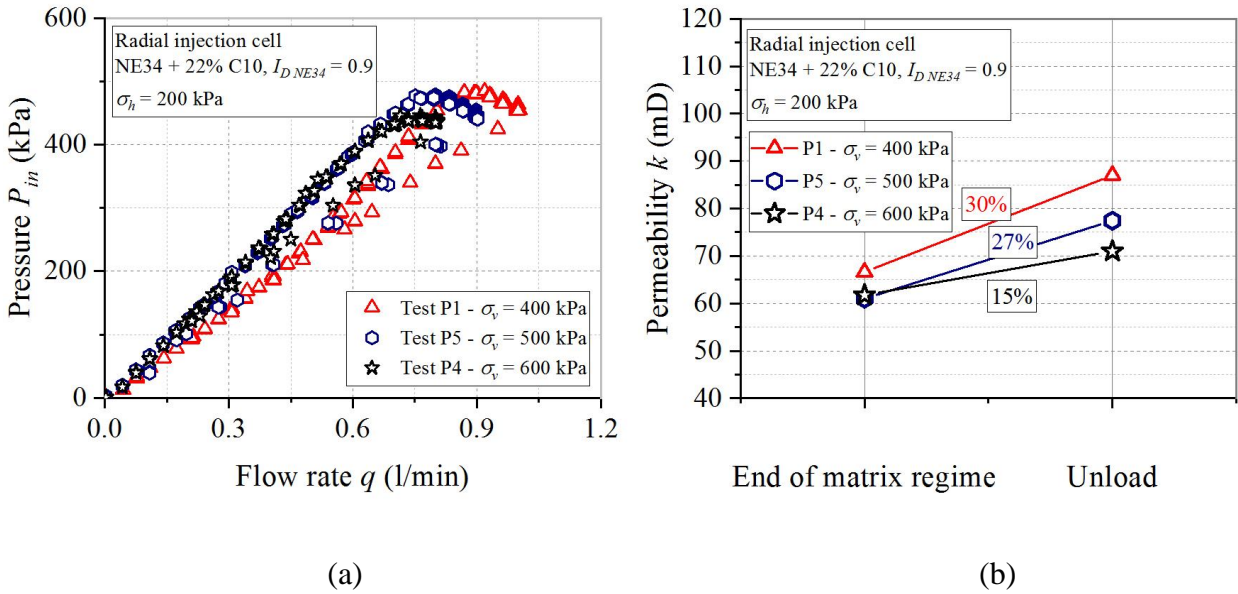
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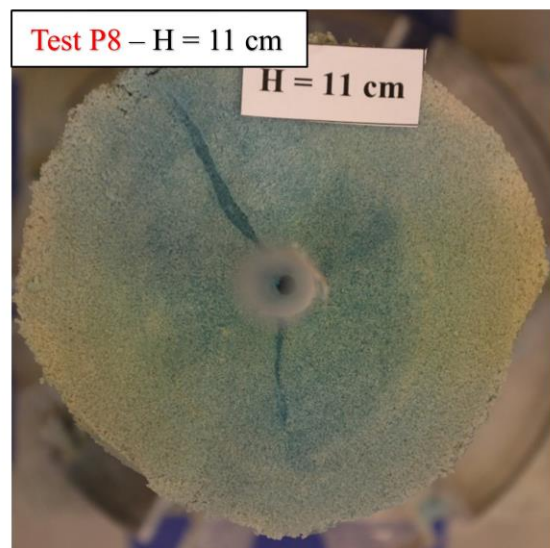
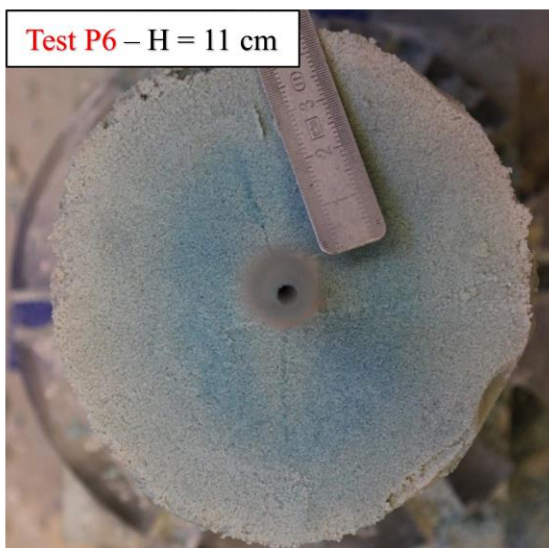
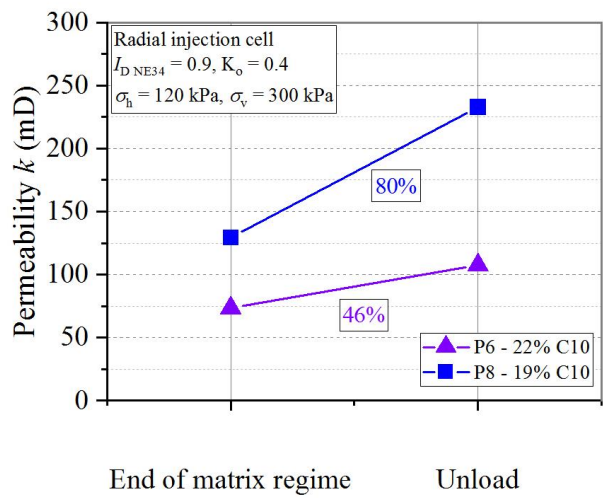
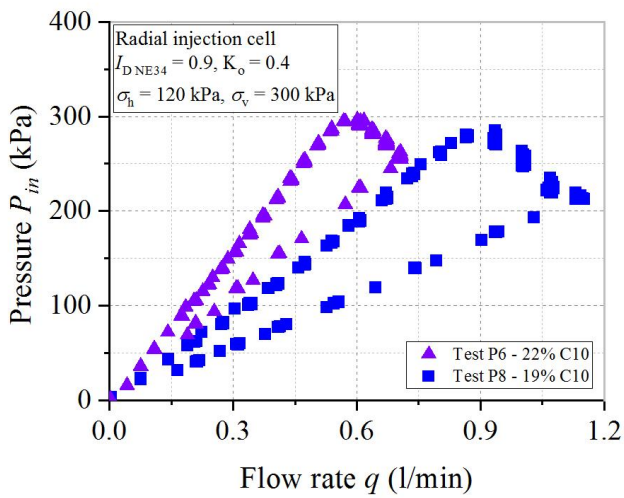
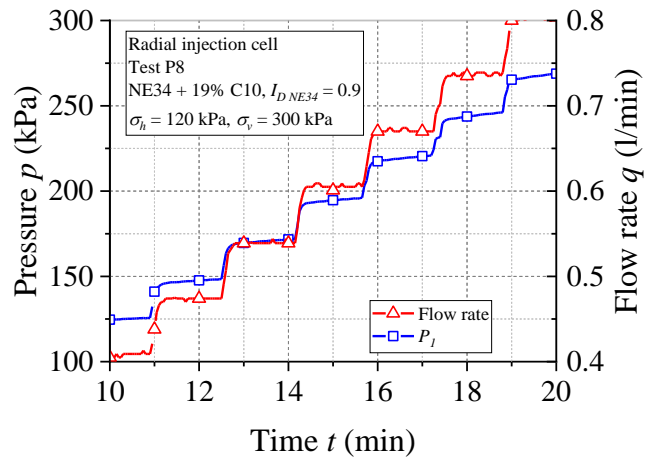
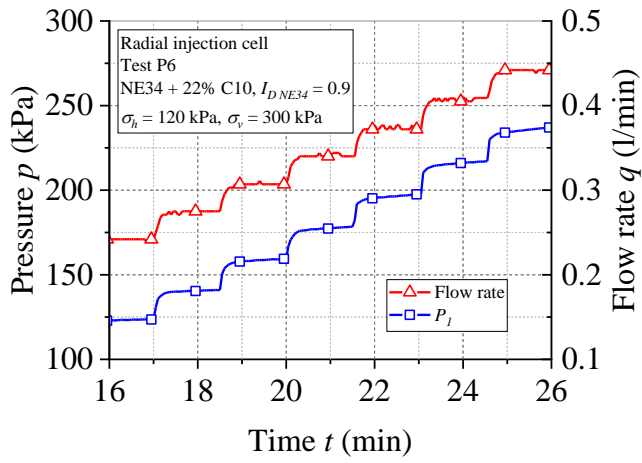
**Fig. 19.** Photos of the horizontal cross-sections corresponding to different depths of excavation in the case of  $K_0 = 0.33$  : (a), (b) test P2; (c), (d) test P4.



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 662 **Fig. 20.** Effect of confining pressure on the normalized fracturing pressure ( $P_{frac}/\sigma_h$ ).



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 664 **Fig. 21.** Effect of the stress ratio coefficient  $K_o$  on: (a) the pressure vs flow rate curves and (b) the  
 665 increase of the overall permeability in the different cases.



**Fig. 22.** Effect of the initial permeability: (a), (b) the pressure – flow rate – time curves during matrix regime of the tests P6 and P8, respectively; (c) the pressure vs flow rate curves; (d) the increase of the overall permeability after fracturing; (e) and (f) typical horizontal cross-sections at  $H = 11$  cm of the tests P6 and P8, respectively.



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Material	$D_{50}$ ( $\mu\text{m}$ )	$C_u$	$e_{min}$	$e_{max}$	Angularity	$\rho_s$ ( $\text{g}/\text{cm}^3$ )
Fontainebleau NE34 sand (after Feia, 2015)	210	1.5	0.55	0.88	Sub- rounded	2.65
C10 silica particles	20	11	-	-	-	2.65

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**Table 1:** Characteristics of the tested materials

	Colloidal	Accelerator	Mixture
Color	Translucent white	Translucent	Translucent white
Viscosity (mPa.s)	10	1	5
Density (kg/l)	1.3	1.07	1.25
pH	9.5 to 9.8	7	~9 (depend on the dosage)
SiO <sub>2</sub> concentration	40 $\pm$ 1	-	-

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**Table 2:** MasterRoc MP320: Data of BASF Construction Chemical Company

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Section	Heigh ( $H$ )	Materials	Total mass ( $m$ )	$I_{D\ NE34}$	Porosity ( $n$ )	Dry density ( $\rho_d$ )
	cm		g		(%)	$\text{g}/\text{cm}^3$
Upper and lower layers of low permeability	2	NE34 + 32% C10	322	0.6	22	2.08
Injection zone	16	NE34 + 22% C10	2082	0.9	23	2.04

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**Table 3:** Characteristics of the reference specimen

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Test condition			Injection zone		Density index of the sand matrix	Fluid injection	
$\sigma_h$ (kPa)	$\sigma_v$ (kPa)	$K_0$	Materials	$k$ (mD)	$I_{D\ NE34}$	Type	$\mu$ (cP)
200	400	0.5	NE34 + 22% C10	$\approx 80$	0.90	Clean water	1

**Table 4:** Characteristics of the reference test

Test	Parameters	Materials		Fluid		Stress conditions			Density index of the matrix $I_{D\ NE34}$	Number of steps of flow rate increase in the fracturing regime
		% C10	$k$ (mD)	$\mu$ (cP)	% fine	$\sigma_h$ (kPa)	$\sigma_v$ (kPa)	$K_0$		
P1	Stress conditions	22	$\approx 80$	1	0	200	400	0.50	0.90	4
P2		22	$\approx 80$	1	0	150	450	0.33	0.90	4
P3		22	$\approx 80$	1	0	350	700	0.50	0.90	4
P4		22	$\approx 80$	1	0	200	600	0.33	0.90	4
P5		22	$\approx 80$	1	0	200	500	0.40	0.90	4
P6		22	$\approx 80$	1	0	120	300	0.40	0.90	4
P7	Flow rate	22	$\approx 80$	1	0	200	400	0.50	0.90	6
P8	Permeability	19	$\approx 150$	1	0	120	300	0.40	0.90	4

**Table 5:** Characteristics of the parametric tests