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Innovative CO_2 injections in carbonates and advanced modelling for numerical investigation

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1. ABSTRACT

CO_2 geological storage in deep saline aquifers was recently developed at industrial scale mainly in sandstone formations. Experiences on CO_2 injections in carbonates aquifers for permanent trapping are quite limited, mostly from US projects such as AEP Mountaineer, Michigan and Williston Basin.

The behavior of fractures in carbonates plays a key role in those reservoirs in which porous matrix permeability is very poor, which drives the CO_2 plume migration through the fracture network where hydromechanics and geochemical effects take place due to injection.

Hontomín (Spain) is the actual on-shore injection pilot in Europe (EP Resolution of 14 January 2014), whose reservoir is comprised of fractured carbonates. Existing experiences from field scale tests conducted on site have supported to better understand the behavior of this type of reservoirs for CO_2 geological storage.

Innovative CO_2 injection strategies are being carried out in ENOS Project (EU H2020 Programme, http://www.enos-project.eu). First results based on field tests conducted at Hontomín, and the advanced modelling developed so far will be analyzed and discussed in this article, as well as, the description of future works. The evolution of operating parameters such as flow rate, pressure and recovery term during the tests confirm the CO_2 migration through the fractures.

Keywords: CO_2 Storage, carbonate fractures, ENOS, operating parameters, advanced modelling

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2. INTRODUCTION

Most of experiences on CO_2 geological storage worldwide have been conducted in rock formations with high permeability in the pore matrix, mainly in sandstones [Michael et al., 2011] [Krevor et al., 2012] [Torp and Gale 2004] and in some cases in carbonates such as AEP Mountaineer Project [Gupta 2008] [Mishra et al., 2013], Michigan and Williston Basin [Finley et al., 2013] [Worth et al., 2014] in USA. There are also CO_2-EOR projects which injects CO_2 in carbonate formations such as the IEAGHG Weyburn-Midale CO_2 project [Wilson and Monea, 2004] in Canada and the Uthmaniyah CO_2-EOR demonstration project in Saudi Arabia [Liu et al., 2012]

The design of safe CO_2 injection strategies and the understanding of trapping mechanisms in carbonates with poor matrix porosity and fluid transmissivity through the fractures are challenging matters so far. To give a proper solution, the study of hydrodynamic and mechanical effects induced by the CO_2 plume migration in the fractures, and those ones produced by the geochemical reactivity due to the acidification of reservoir water, is needed to increase the knowledge on the behavior of these reservoirs for CO_2 geological storage and later industrial deployment [de Dios et al., 2017].

Hontomín Pilot Plant [Neele et al., 2014], operated by Fundación Ciudad de la Energía (CIUDEN), is the only current onshore injection site in Europe for CO_2 geological storage, recognized by the European Parliament [EP resolution 2014] as key test facility for CCS technology development. The pilot is located close to Burgos in the north of Spain, and its reservoir is comprised of fractured carbonates with poor matrix porosity [Campos et al., 2014].

To demonstrate innovative injection strategies and history matching approaches for increased confidence of operators in safely managing sites is a priority within ENOS Project (EU H2020 Programme, http://www.enos-project.eu). It is expected to increase the understanding on CO_2 injection in fractured carbonates with low primary permeability, and to develop safe and efficient operational procedures using real-life experience from running the Hontomin pilot [Gastine et al., 2017].

CO_2 injection in rock formations with main fluid transmissivity through fractures usually requires high values of pressure, which means a risk for the pair seal-reservoir integrity [Vilarasa et al., 2014]. On the other hand, as mentioned above, the geochemical reactivity due to reservoir water acidification impacts on the carbonate permeability [Gaus et al., 2015]. These matters must be considered to design safe and efficient injection strategies in ENOS project to improve the hydrodynamic stability and control of storage integrity. First injections conducted at Hontomín using synthetic brine and CO_2 will be described in the article, analyzing the evolution of operational parameters and discussing the results.

To model the CO_2 migration through the fractures and predict the injection effects in the carbonates is a challenge as well. An advanced modeling workflow with FracaFlow™ used to elaborate a Digital Fracture Network (DFN) [Bourbiaux et al., 2005] around the injection well and characterize the main properties of the fracture network will be described in the article. The dynamic characterization of fracture properties was then performed using an advanced automated history matching with CMOST™ to model the pressure behavior around the injection well based upon a previous modelling work [Le Gallo et al., 2017].

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Taking into account the first results from injections and the modelling developed so far, the authors will describe the planned works to be conducted in ENOS project in order to find solutions based on real life experiences.

The results from first injections performed at Hontomín site confirmed the singularity of this reservoir where CO_2 migration is through the carbonate fractures. The evolution of main operational parameters such as well head pressure (WHP), flow rate, bottom-hole pressure (BHP) and distributed temperature along the well tubing confirm the injection of CO_2 in liquid phase. Taking into account the information provided by the first results, it is necessary to determine the long term evolution of BHP and flow regarding the injection strategy used and particularly the pressure recovery period during the fall-off phase according to the cumulative amount of CO_2 injected on site.

3. DESCRIPTION OF PILOT PLANT

Hontomín site represents a structural dome where the pair seal-reservoir is located within Jurassic Formations (Marly Lias and Sopeña respectively). Overburden is formed of Dogger, Purbeck and Weald and the underlying seal is located at Triassic Keuper [Rubio et al., 2014]. Figure 1 shows the lithological column of Hontomín site and the geological cartography of the area.

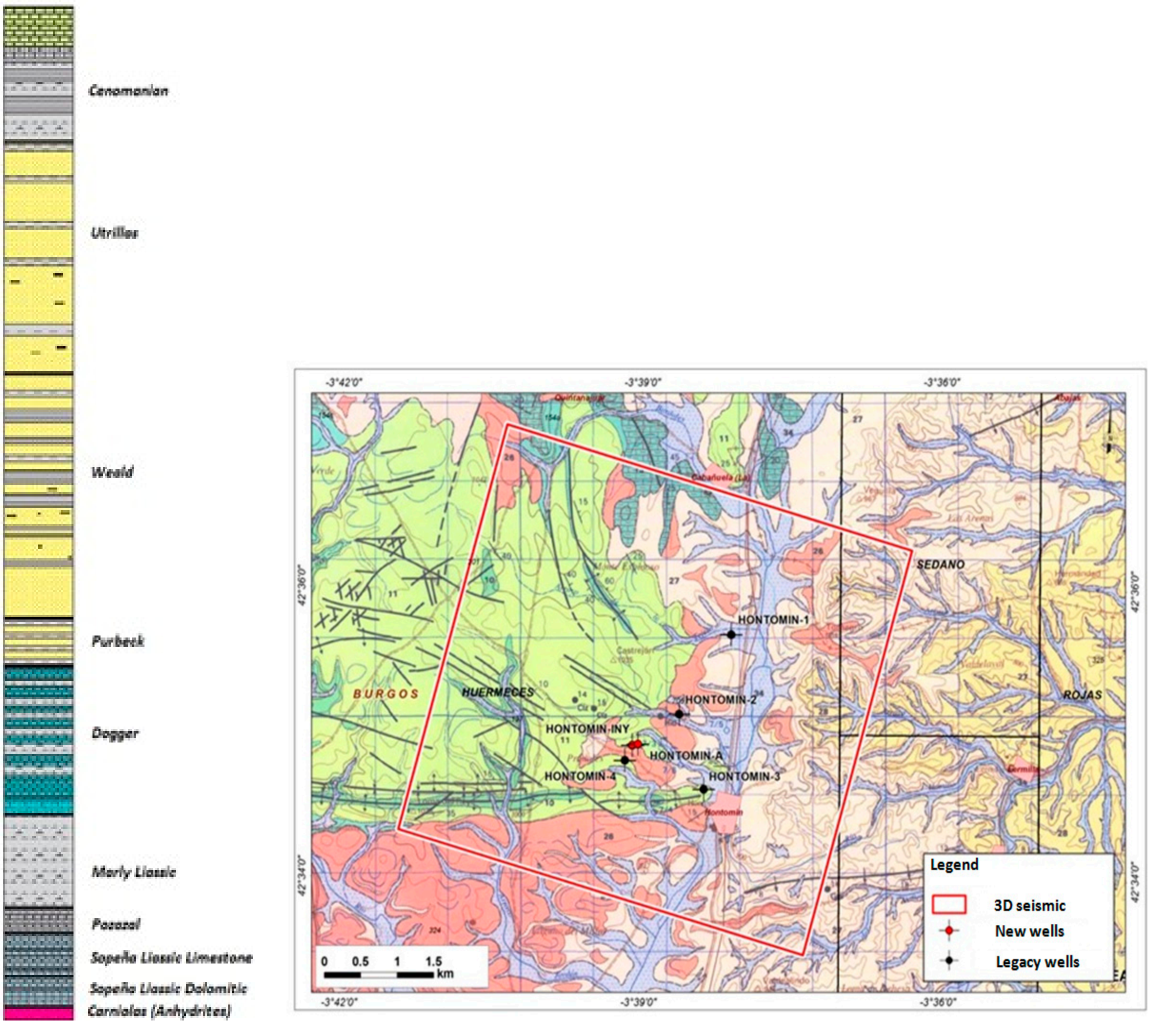
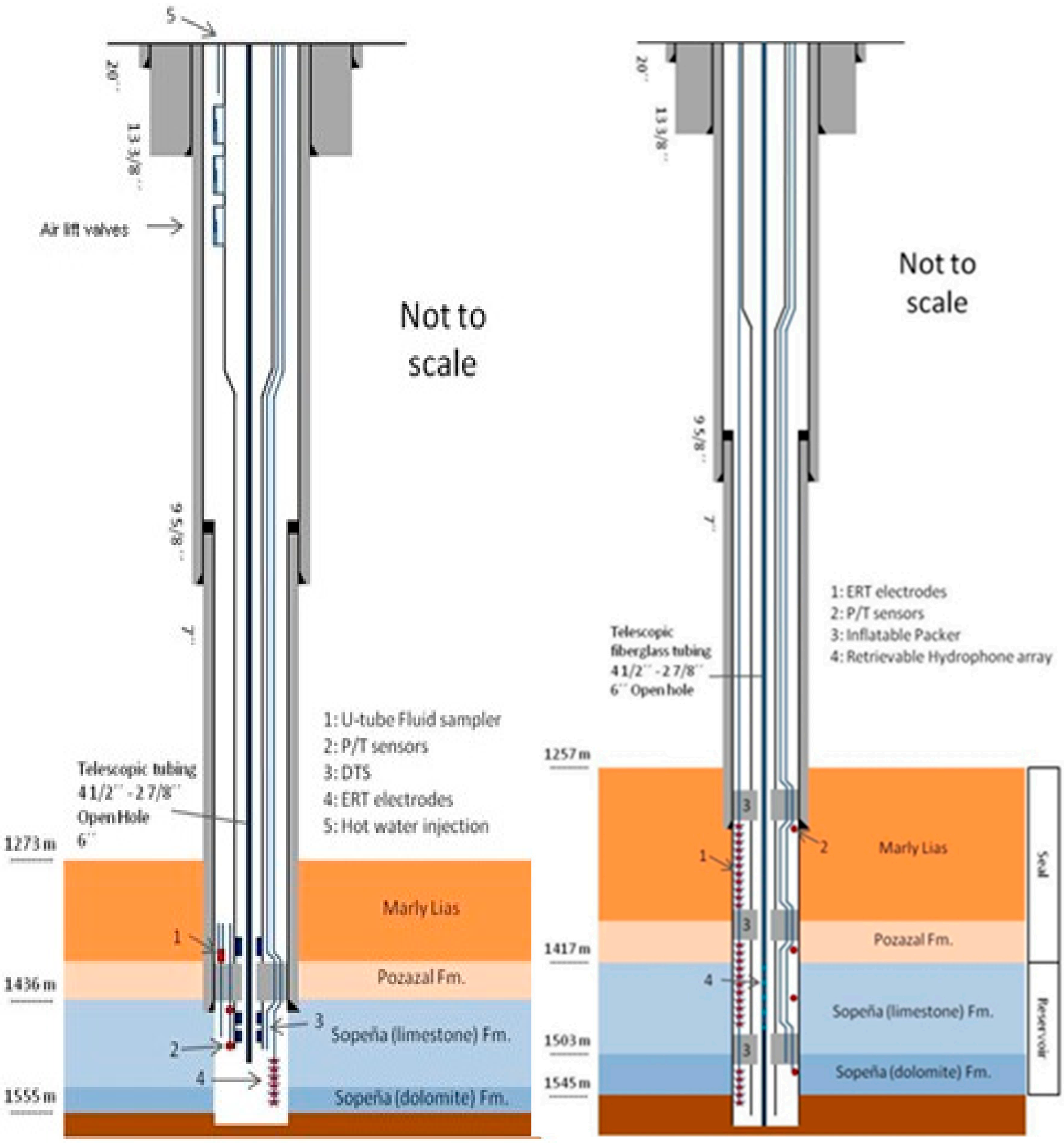


Fig 1.- Lithological column and geological map of Hontomín area

Pair seal-reservoir is located at the depth of 900 in the top of the dome and 1832 m in flanks. Marly Lias and Pozazal form the main seal (160 m thick) comprised of marls, shales, limestones and calcareous mud stones. Carbonates reach the average of 50% in the seal composition. Reservoir is Sopeña Formation (120 m thick) comprised of limestone at its upper part and dolomites at the bottom [Kovacs 2014], with a high level of fracturing in different geological blocks which does not affect the seal integrity.

Two wells were specifically drilled and monitored during the site construction reaching the depth of 1600 m, one for injection (HI) and other for observation (HA) [de Dios et al., 2016]. HI well is equipped with super duplex tubing anchored to the liner by a hydraulic packer (1433 m MD), two P/T sensors below, Distributed Temperature Sensing System (DTS) and Distributed Acoustic Sensing System (DAS) along the tubing, six ERT electrodes and a deep water sampling (U tube) installed in the bottom hole.

On the other hand, HA well is equipped with a fiber glass tubing anchored to the liner with 3 inflatable packers (1275 m, 1379 m and 1497 m MD) which distribute the open hole in intervals with different permeability, 4 pressure/temperature (P/T) sensors and 28 ERT electrodes installed in the seal and reservoir. Both well schemes are shown in figure 2.



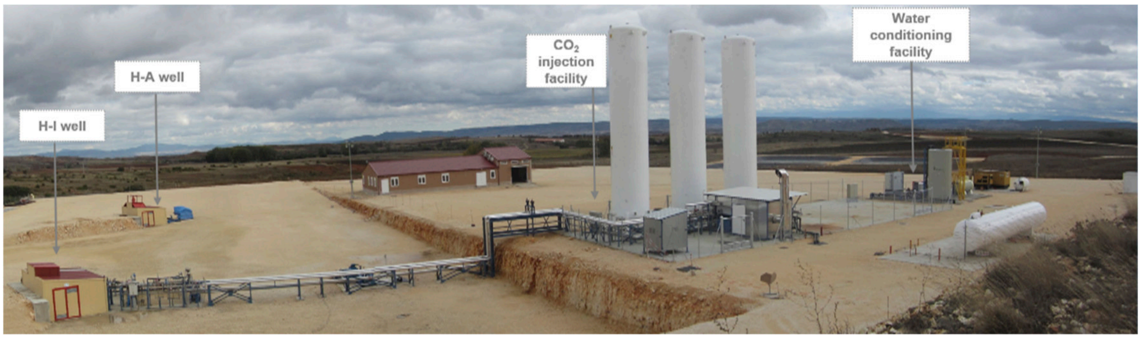


Fig 2.-Schemes of injection well HI (left side) observation well HA (right side) and panoramic view of the pilot

Facilities for CO_2 injection and water conditioning, the seismicity monitoring network comprised of 30 passive seismic stations covering an area of 18 Km^2 and hydrogeological monitoring wells to control shallow aquifers also form part of the pilot.

The main challenge faced during Hontomín hydraulic characterization was the low injectivity existing on site. The injection of brine and CO_2 to characterize the pair seal-reservoir produced geomechanical changes and geochemical reactivity effects that improved the permeability in the fracture network while the matrix does not appear to significantly contribute to the storage capacity for the time being [de Dios et al., 2017].

Hontomín is at the early injection phase, thus, all long term effects that condition the safe and efficient CO_2 geological storage must be determined and analyzed.

4. INNOVATIVE CO_2 INJECTION STRATEGIES

It is planned to inject on site up to 10 000 metric tonnes of CO_2 during the period 2016-2020 in ENOS project, with the purpose of better knowing the behavior of this tight fractured reservoir, mainly what concerns the improvement of hydrodynamic stability and control of storage integrity, for finding safe and efficient operation conditions.

Therefore, the design of CO_2 injection strategies to be conducted in the project must be based on criteria of efficiency and safety, for later up-scaling to industrial deployment. The operating procedures must ensure efficient energy consumption, maximizing reservoir capacity and preserving seal integrity [Gale et al., 2001].

As mentioned before, CO_2 injection in carbonate reservoirs with low matrix permeability shows specific features that are different from injection in porous media. Considering the CO_2 migration is dominated by the fracture network, the following gaps need to be studied in order to define proper strategies for the injection:

- Bottom-hole pressure (BHP) evolution and its influence in the cap-rock integrity and reservoir behavior
- Bottom-hole temperature (BHT) evolution and the analysis of thermal effects due to injection
- Monitoring CO_2 evolution along the well tubing and the fluid density reached at the bottom hole.
- Energy consumption and operation performance for each planned injection

Most of existing experiences worldwide were based on continuous flow of injected CO_2 [Nordbotten et al., 2004], but taking into account that in future storage operations at industrial scale unexpected effects may occur, such as high pressure values reached at the reservoir that put in risk the seal integrity and/or low injectivity that conditions the process efficiency, it is needed to design and test injections adapted to these scenarios.

First injections conducted at Hontomín in ENOS were developed in discontinuous process, what supposed to inject brine or CO_2 in periods of 8, 24 or 48 hours in order to assess the evolution of pressure and flow, and to determine the term for BHP recovery during the fall-off periods. These discontinuous strategies aim at studying the improvement of hydrodynamic stability in the fractured reservoir.

The use of brine and CO_2 seeks to compare the results with each fluid, with different hydraulic properties as density and viscosity. Usually, first tests are conducted with brine in order to refine the design and performance of CO_2 injections according to the prior results.

High pressure values are necessary to inject CO_2 in Hontomín site, with longer pressure recovery periods than media with transmissivity dominated by matrix porosity. Unexpected reservoir behavior could take place during the injections planned in ENOS project, conditioned to the cumulative amount of CO_2 injected on site and the bottom hole pressure evolution. That means it is needed to analyze the evolution of the injected flow maintaining a safe BHP value and also the evolution of the pressure values while injecting CO_2 at constant flow rate.

In order to address these goals two types of tests were designed:

- Injection tests in pressure control mode
- Injection tests in flow control mode

In the injections monitored by pressure, the setpoint corresponds to the well head pressure (WHP) value in the range of 60-80 bar. In CO_2 injection case, the setpoint is always equal or higher than 75 bar to ensure the liquid phase of injected fluid, taking into account the temperature at the well head (WHT) is usually set in the range of 10-30º C.

On the other hand, in the tests that use flow rate as control parameter, the setpoint is in the ranges of 1-2 kg/sec using CO_2 and 1-3 kg/sec for brine, which are consistent with the existing capabilities of CO_2 injection and water conditioning facilities.

Figure 3 shows the evolution of BHP data from two P/T sensors (see figure 2) located in the open hole of HI well, WHP in the injection well, BHP from the P/T sensor located in the seal of HA well (see figure 2) and flow rate of brine and CO_2 during 8 hours of CO_2 injection in flow control mode (setpoint 2 kg/sec).

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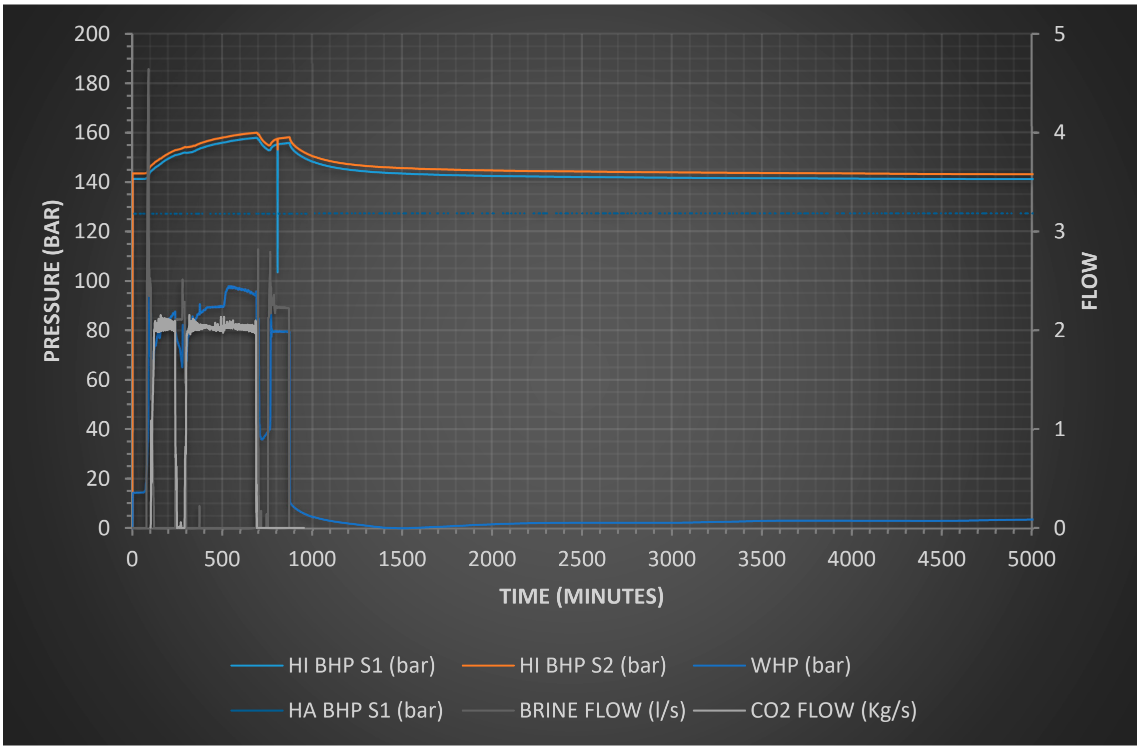

Fig 3.- Evolution of operating parameters for 8 hours of CO_2 injection in flow control mode

Brine flow rate belongs to previous phase of CO_2 injection for pressurizing the well to 75 bar, subsequently to clean up the tubing [de Dios et al., 2017] and during a short halfway period due to a problem in the CO_2 pumps. Initial and final values of referred parameters during CO_2 injection are shown in table 1. BHP in HA well remains constant along the test what proves there is not fluid transmissivity through the seal.

Table 1 Operating parameters for 8 hours of CO_2 injection in flow control mode (2 kg/sec)

Parameter	Initial value	Final value (8 hours)
WHP	75 bar	98 bar
HI BHP (S2)	144 bar	159 bar
WHT	10º C	10º C
Flow	2 kg/sec	2 kg/sec

Despite being a short injection, since the operation period was 8 hours, as CO_2 permeates and push the reservoir water through the fractures it was needed a final incremental of well head pressure close to 30 % from initial value to maintain the flow rate value of 2 kg/sec along the test. Therefore, future injections must prove if pressure evolution follows the trend showed in the short term or not, being necessary to conduct tests during longer periods in similar conditions.

The main goal is to assess if the final BHP of 180 bar, considered a safe value to preserve the pair seal-reservoir integrity, is reached, and to determine additionally the period of time needed, the operational conditions and the cumulative amount of CO_2 existing on site when it occurs.

BHP evolution shown in figure 3 reveals a final overpressure of 15 bar from the hydrostatic value existing previously to the injection start. At the beginning and end of the test WHP reached the values of 75 and 98 bar respectively with BHP values of 144 and 159 bar. Pressure incremental at the well head is not proportional to the overpressure at the bottom hole, which is due to a choke was installed in the HI well tubing to ensure the integrity of the pair seal-reservoir [de Dios et al., 2017] what produced a pressure drop at the bottom hole during the injection.

On the other hand, this test was conducted once several injections were carried out using firstly brine and subsequently CO_2 as mentioned above, with recovery periods during the fall-off phase in the range of 48-60 hours for a pressure recovery range of 95-100%. New tests aim to analyze how BHP recovery will be regarding the final pressure value reached in the reservoir and the cumulative amount of CO_2 injected on site.

Figure 4 shows the evolution of the operating parameters for 24 hours of CO_2 injection in pressure control mode (set point 80 bar). These data are: BHP from HI P/T sensors, WHP in the injection well, BHP from P/T sensor located in the seal of the HA well and the flow rate of brine and CO_2.

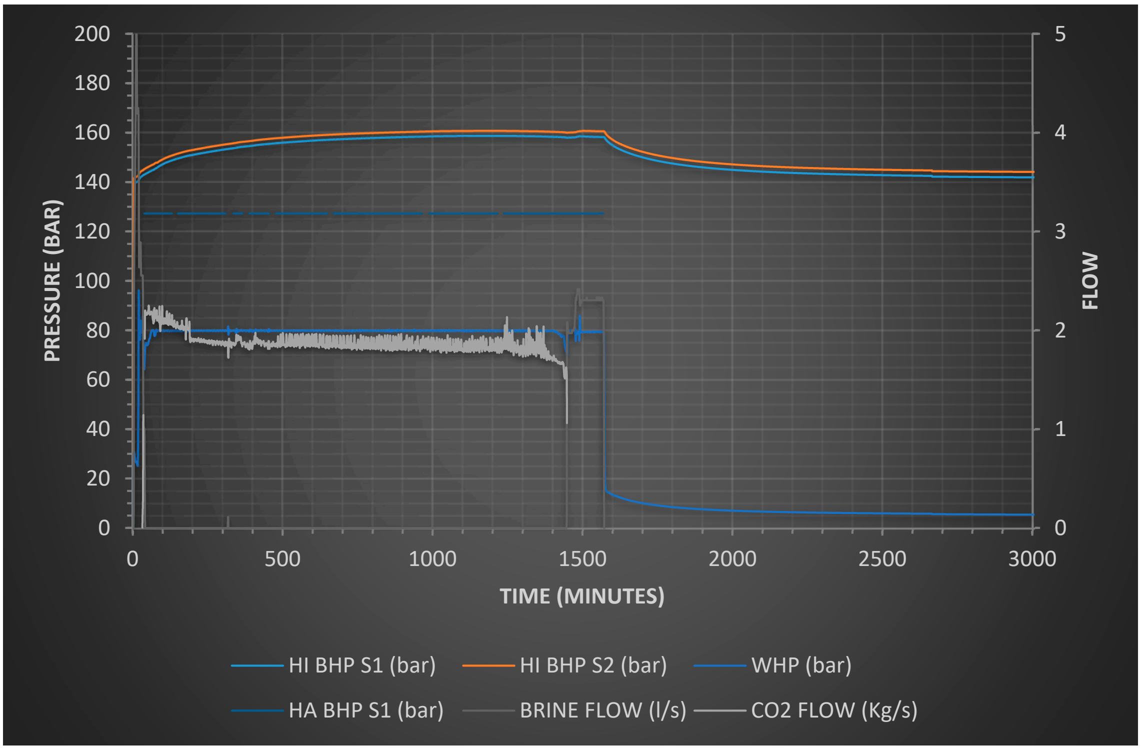

Fig 4.- Evolution of operating parameters for 24 hours of CO_2 injection in pressure control mode

The initial and final values of the operating parameters during the injection are shown in table 2.

Table 2 Operating parameters for 24 hours of CO_2 injection in pressure control mode

Parameter	Initial value	Final value (8 hours)
WHP	80 bar	80 bar
HI BHP (S2)	142 bar	160 bar
WHT	10º C	10º C
Flow	2.2 kg/sec	1.7 kg/sec

The reservoir behavior is different depending on each injection phase. Thus, initially a flow of 2.2 kg/sec injected into the reservoir was needed to hold the WHP value of 80 bar. As the fluid fills the fractures, this value decreases up to reach 1.7 kg/sec at the end of the test, what suppose 23% less than the initial flow value. As happened in the injection conducted in flow control mode

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analyzed above, hydrodynamic effects induced by the injection in the fractures play a key role to understand the reservoir behavior. It is also needed to conduct tests during longer periods in similar conditions for checking if the flow evolution follows the trend showed in the short term or not, and if safe BHP value of 180 bar is reached and when it happens.

This test was the last one of eleven injections, six of them performed with 430 m^3 of brine and the rest with 490 metric tonnes of CO_2. A period of 15 days was needed to recover 98% of initial BHP value, while in similar tests conducted with brine the recovery period was close to 10 days. This fact may be due to supercritical CO_2 is a compressible fluid affected by the closure of fractures during fall-off periods when the injection stops, what conditions the biphasic migration of CO_2 and brine through the fracture networks. On the other hand, as much CO_2 is injected on site BHP increases in the reservoir and longer periods for pressure recovery are needed.

As regards the thermodynamic parameters along the injection well and open-hole that determine the operation performance and thermal effects into the reservoir, figures 5 and 6 show respectively the thermal profile along HI tubing and BHT evolution during the 24 hours injection test in pressure control mode.

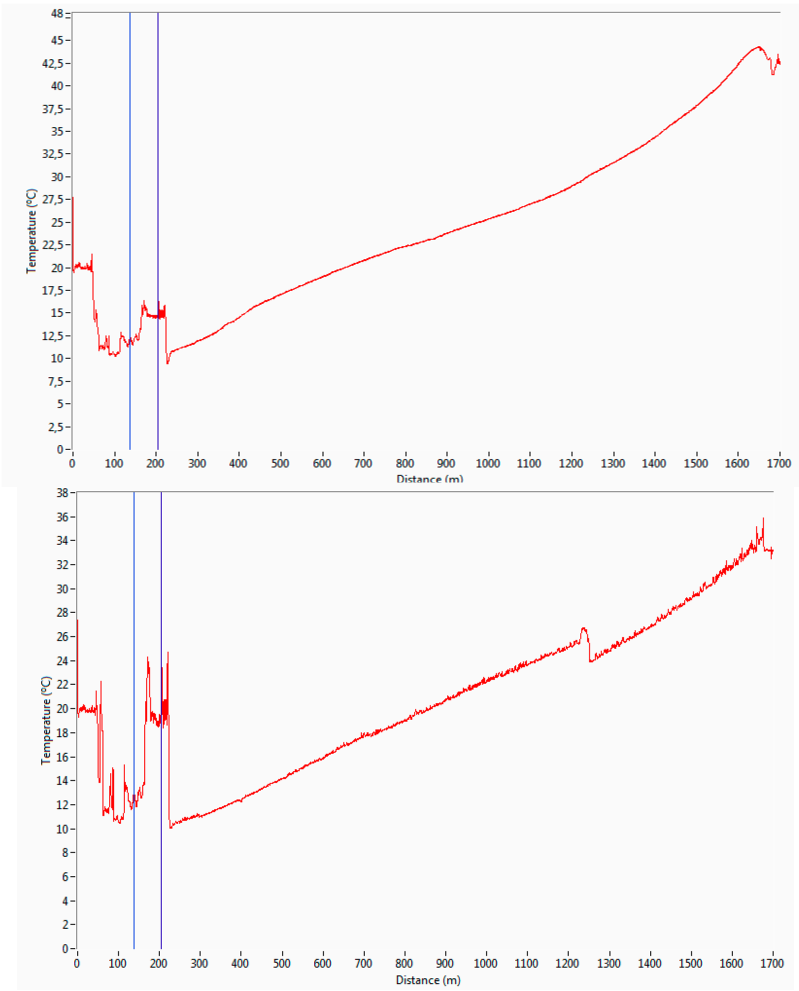

Fig 5.- Thermal profile of HI well tubing previously (top) and during CO_2 injection (bottom)

The graphic at the top of figure 5 shows the temperature values along the HI well tubing previously the injection. The graphic in the bottom corresponds to values recorded at the final phase of CO_2 injection. The data were recorded by a Distributed Temperature Sensing System (DTS) [Hilgersom et al., 2016] anchored to HI well tubing (see figure 2).

In both graphics, the range of temperatures corresponding to the distances between 0 and 200 m belongs to the part of DTS optic fiber buried close to surface to connect the control room with HI well head, and therefore, these data correspond to environmental temperature and do not have to be taken in consideration.

Graphic at the top of figure 5 shows homogeneous thermal gradient of the existing brine in the annular space between the tubing and the casing/liner, which could be quite similar to geothermal gradient. Hontomín reservoir is a “cold” formation taking into account the BHT value was 44º C prior to injection.

On the other hand, the graphic at the bottom of figure 5 shows the temperature evolution along the tubing once 22 hours of CO_2 injection were conducted on site. The heating and subsequent cooling for the distance of 1200 m (1000 m MD depth in HI well), correspond to effects induced by the choke [van der Zante and van der Broek, 1998] located in this position of well tubing mentioned above. Initially CO_2 heating is produced due to friction between fluid and the wall of choke and finally the cooling due to the Joule-Thomson effect produced by the CO_2 expansion at the choke exit [de Dios et al., 2017].

The BHP value of 16O bar (figure 4) and temperature along the tubing (bottom of figure 5) reveal that the injection was performed with liquid CO_2, reaching a fluid density at HI bottom hole of 0,828 t/m^3 at the end of the test.

As regards the thermal effect produced in the saline aquifer due to CO_2 injection, figure 6 shows the evolution of BHT data from P/T sensors of HI well, WHT in the injection well, BHT in the sensor located into the seal of HA well and flow rates of brine and CO_2 for the 24 hours of CO_2 injection test in pressure control mode.

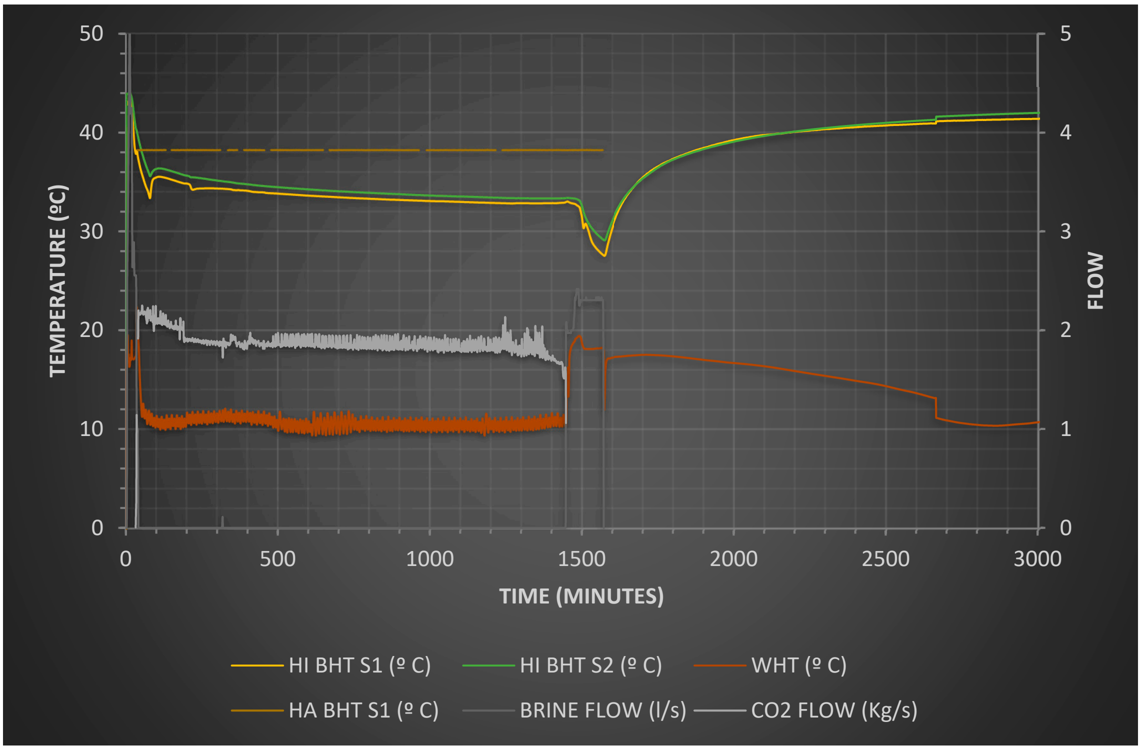

Fig 6.-Evolution of BHT and WHT during 24 hours of CO_2 injection in pressure control mode

The gradual cooling of reservoir water happened for the 24 injecting hours from 44º C, that was the BHT initial value, to 33º C taking into account the wellhead maintained an averaged temperature value of 10º C during CO_2 injection, as figure 6 shows. Relevant temperature decrease at HI bottom hole occurred due to the injection of brine previously to CO_2 injection in order to pressurize the well head to 75 bar, and subsequently to clean up the tubing when CO_2 injection finalized, as mentioned above, while BHT in HA remains constant at the seal what proves its integrity.

The injection tests are being analyzed from the hydraulic characterization phase with a compositional dual media model which accounts for both temperature effects and multiphase flow hysteresis [Le Gallo et al., 2017], to effectively simulate the alternating brine and CO_2 injection tests that were and will be conducted on site. Next point adresses the modelling developed so far to characterize the fractured carbonates at Hontomín site for CO_2 geological storage.

5. MODELLING OF CO_2 MIGRATION THROUGH FRACTURES

The injection tests are modeled with GEM™, a commercial compositional dual media model which accounts for both temperature effects and multiphase flow hysteresis [Le Gallo et al., 2017] as liquid CO_2 and brine are injected during the tests. The previous model was first improved with a better characterization of the vertical and lateral heterogeneities [Le Gallo and de Dios, 2018]. To best reproduced the well pressure response of the model, a two level grid refinement is applied around the injection well which refines the initial 50x50 m^2 reservoir grid to about 1.5x1.5 m^2 without changing the vertical layering (39 layers in the Sopeña formation). The base case model is further improved through advanced fracture modelling. The fracture network is first characterized with FracaFlow™ showing two main sets of fractures [Le Gallo and de Dios, 2018]. A Discrete Fracture Network (DFN) is generated within FracaFlow™ around the injection well and matched to interpreted injection tests [Le Gallo et al., 2017]. The DFN is then upscaled into the reservoir grid inducing an anisotropy of fracture permeabilities due to the orientation of the two sets of fractures. In this approach, there are significant uncertainties regarding the various parameters of the fractures such as aperture and permeability which strongly influence the model response.

Therefore, an advanced uncertainty workflow is used to best tune the model to the well conditions. The modelling followed a sequential approach: first matching the single phase parameters such as fracture permeability during the brine injection periods and then matching the two-phase parameters such as fracture relative permeability during the brine and CO_2 injection periods.

In order to minimize the number of model parameters, e.g. avoiding modelling the flow behavior within the well, the well flow rates are modeled at reservoir conditions aiming at matching the measured bottom-hole pressure. The well parameters are acquired every minute and would consequently limit the simulation time step, thus the well parameters are averaged on an hour basis while ensuring consistency of mass balance and synchronicity of model with well operations.

5.1 MODELLING SINGLE PHASE BRINE INJECTIONS PERIODS

Based upon the previous modeling work [Le Gallo et al., 2017], several single phase parameters are considered within the CMOST™ uncertainty modelling workflow to best enable pressure matching:

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- Multipliers for fracture permeabilities in each of the 3 directions of the grid which vary several orders of magnitude with uniform distributions
- Multiplier for matrix permeabilities (identical in each of the 3 directions of the grid) which varies one order of magnitude with an uniform distribution since the matrix permeability was previous matched [Le Gallo et al., 2017]
- Multiplier for fracture porosity which varies 50% with an uniform distribution since the base model was previous matched [Le Gallo et al., 2017]
- Multiplier for matrix porosity which varies 50% with an uniform distribution since the base model was previous matched [Le Gallo et al., 2017]
- Compressibility of matrix and fracture medium which vary several orders of magnitude with uniform distributions to best improve the pressure response during fall-off periods

The uncertainty model CMOST™ investigates the parameter domain based upon a Latin Hypercube Sampling approach and converges towards its optimum after about 80 different simulations as shown in figure 7. Beyond the initial 100 simulations, no significant improvement of the match (cumulative difference between simulated and measured BHP for HI well) is obtained and the residual relative error is about 7% as shown in figure 8 which mainly corresponds to the slight mismatches during the fall-off periods. The single phase match is quite satisfactory and the most influential parameters, shown in figure 9, are:

1. Multiplier for fracture permeability in the I direction (north-south)
2. Multiplier for fracture permeability in the J direction (east-west)
3. Multiplier for fracture porosity

The brine single phase flow in the carbonate reservoir is mainly influenced by the fracture characteristics (permeability and porosity) and to a lesser extent by the matrix ones. The optimal match shown in figures 7 and 8 is then used as base case to model the two phase CO_2-brine injection periods.

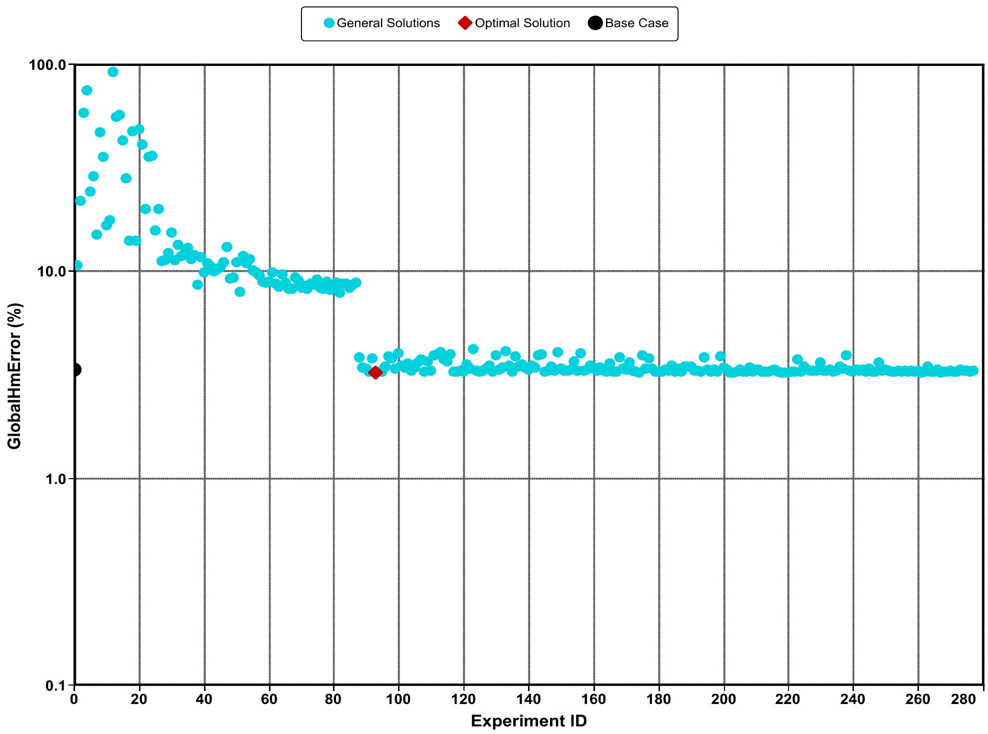

Fig 7.-Evolution of objective function characterizing the error between model and well measurements with the number of simulations

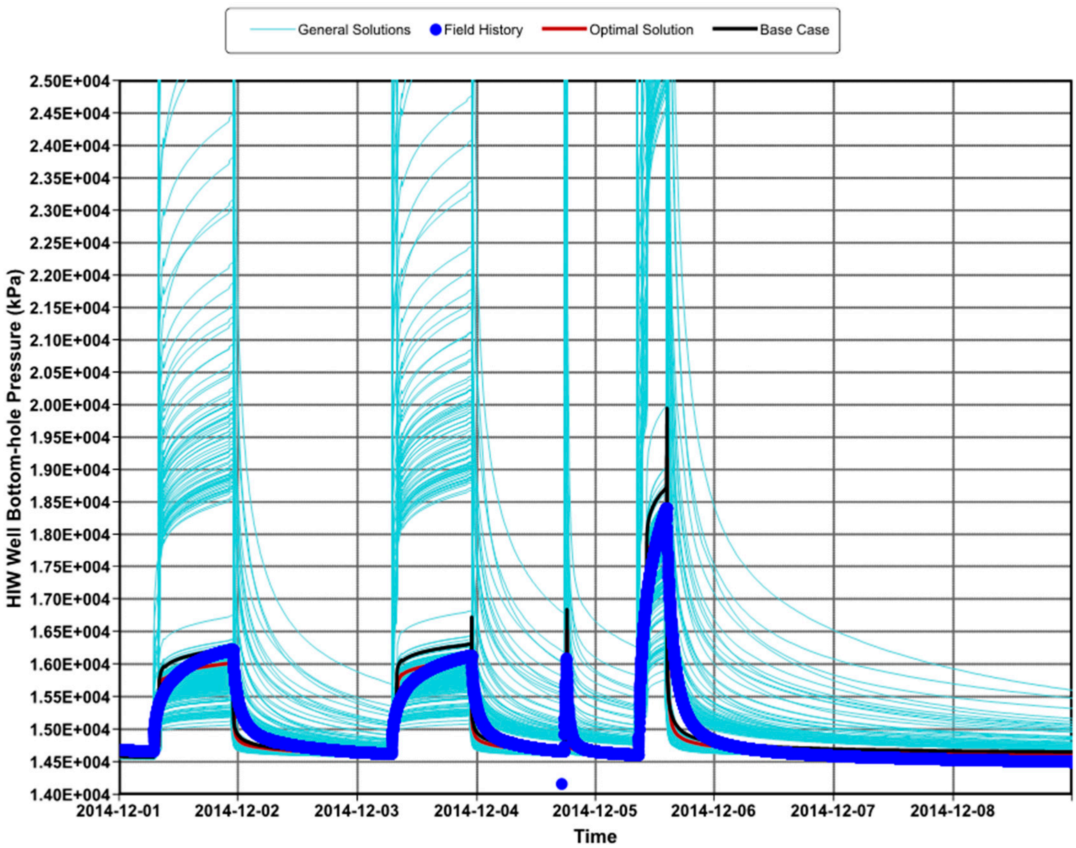

Fig 8.-Evolution of the bottom-hole pressure at the injection well HI during the single phase history matching.

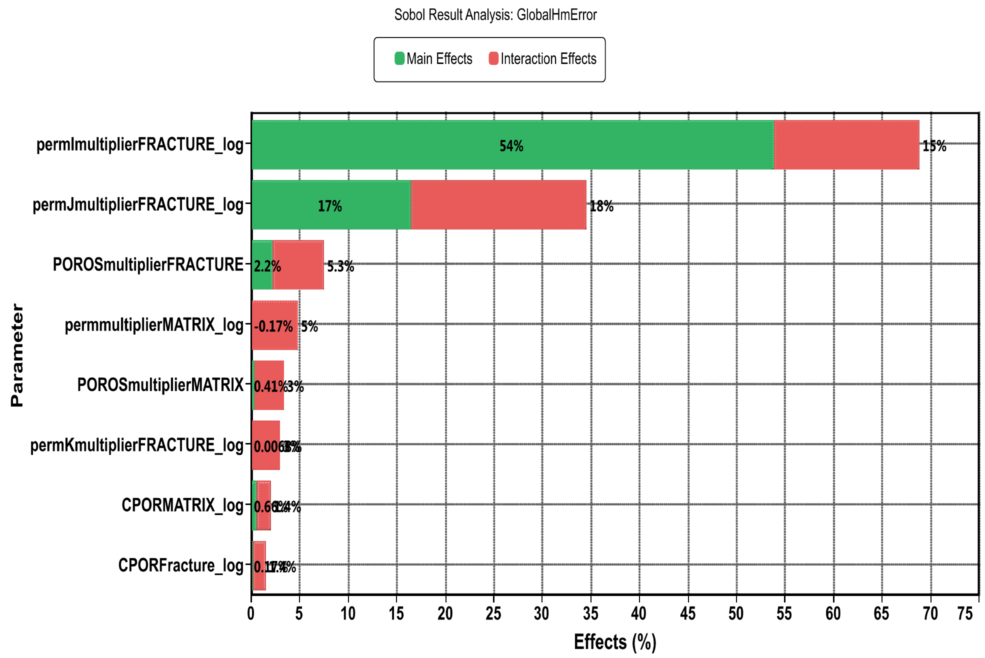

Fig 9.-Most influential parameters on objective function characterizing the error between model and well measurements

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5.2 MODELLING TWO PHASE BRINE & CO_2 INJECTION PERIOD

As flow in this naturally fractured carbonate reservoir is controlled by fracture characteristics, the two-phase parameters selected are related to the fracture relative permeability for the CO_2-brine as shown in figure 10

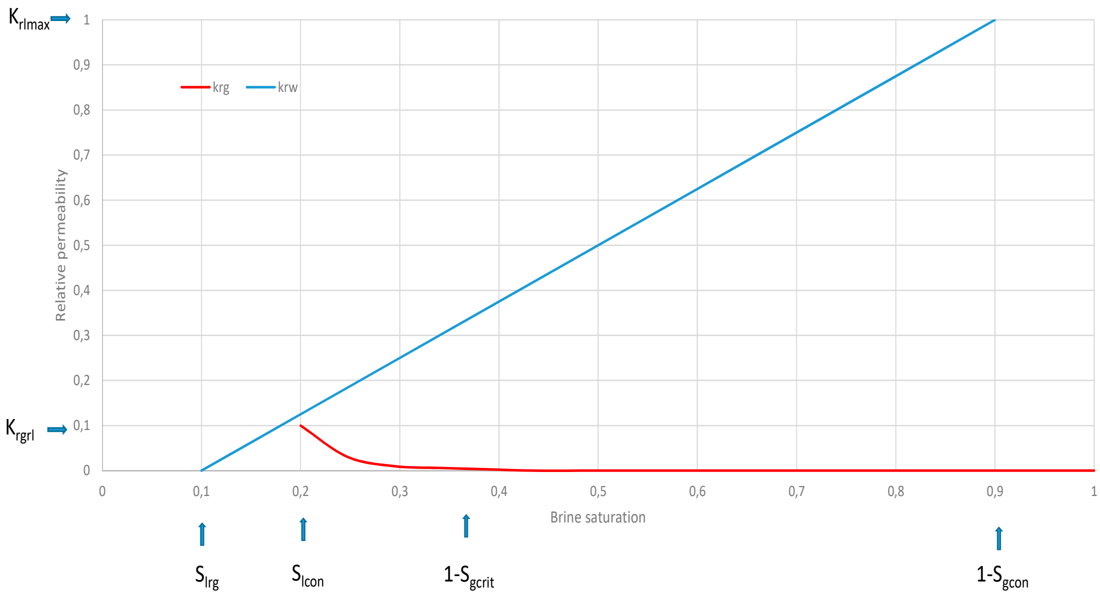

Fig 10.- CO_2-brine relative permeability in the fracture [Le Gallo et al., 2017]and end-points used in history-matching

The two-phase parameters adjusted within the CMOST™ uncertainty modelling workflow are the following end-points (see figure 10) of the relative permeabilities for the fractures:

- The maximum of the CO_2 relative permeability, KRGRL, which may vary between 0.01 and 1 with a uniform distribution
- The maximum of the brine relative permeability, Krlmax, which may vary between 0.75 and 1 with a uniform distribution
- The CO_2 critical saturation, OneminusSGcrit, which may vary between 0 and 0.5 with a uniform distribution
- The brine critical saturation, SLrg, which may vary between 0.1 and 0.25 with a uniform distribution

The ranges of variation of these parameters are determined based upon the previous modelling work [Le Gallo et al., 2017]. Using the best results from the single phase modelling (base case in this workflow), the uncertainty model CMOST™ investigates the parameter domains based upon a Latin Hypercube Sampling approach and converges towards its optimum after about 30 different simulations as shown in figure 11. Beyond the initial 50 simulations no significant improvement of the match is obtained and the residual relative error is about 4.5% as shown in figure 12, which mainly corresponds to the mismatches during the fall-off periods. The two-phase match is quite satisfactory and the most influential parameters, shown in figure 13, are:

1. The maximum of the CO_2 relative permeability, KRGRL, which optimum is at about 0.035
2. The CO_2 critical saturation, OneminusSGcrit, which optimum is at about 0.49

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3. The maximum of the brine relative permeability, Krlmax, which optimum is at about 0.769

The optimal solution after the history matching is shown in figure 11. The main mismatches between the field and simulation occur during the fall-off period as the simulated pressure always returns faster than the measured pressure to its base level. An attempt to mitigate this discrepancy was to account for the uncertainty to rock compressibility and to numerical dispersion due to grid size. The current results significantly improve the previous modelling results [Le Gallo et al., 2017]. However, the influence of the compressibility of the various rock facies is not significant as shown in figure 9.

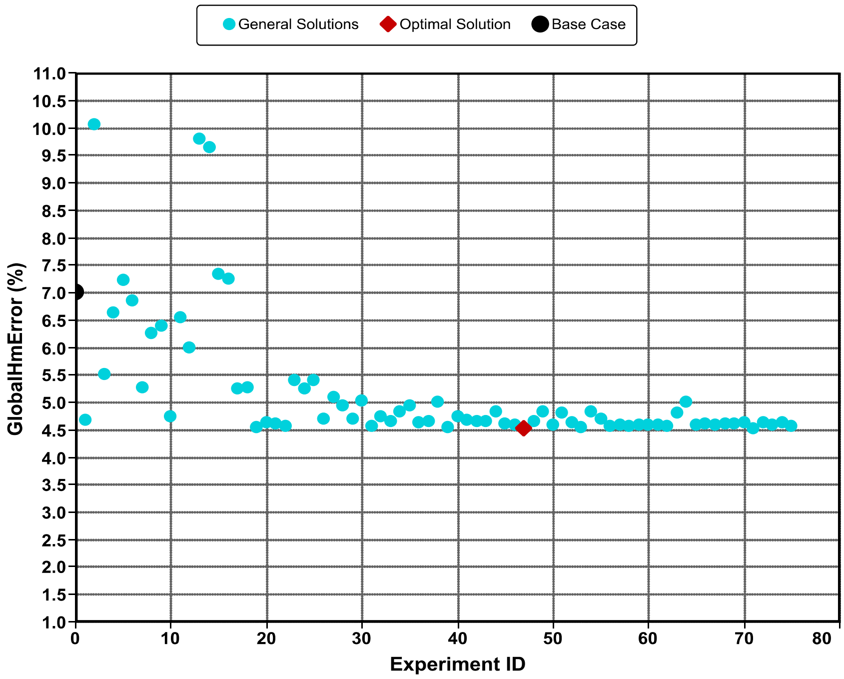

Fig 11.-Evolution of objective function characterizing the error between model and well measurements with the number of simulations

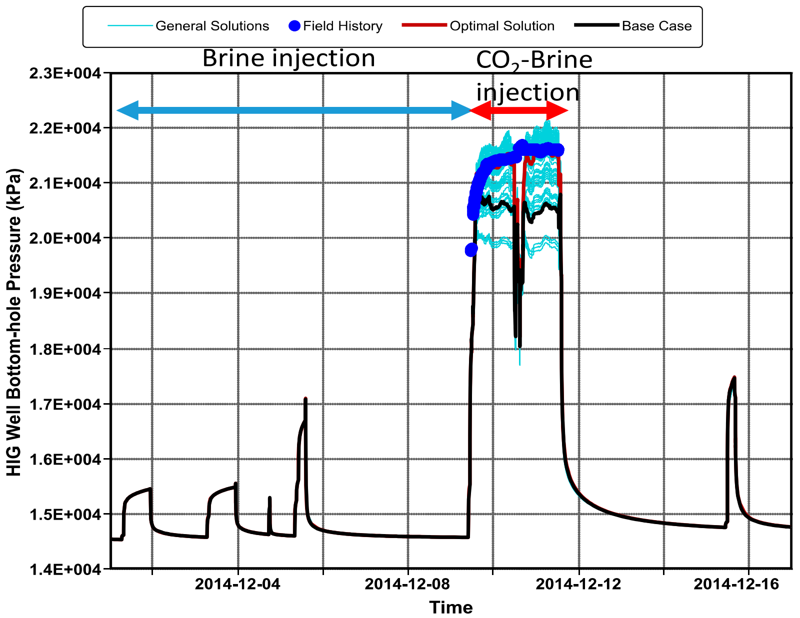

Fig 12.-Evolution of the bottom-hole pressure at the injection well HI during the CO_2-brine injection period

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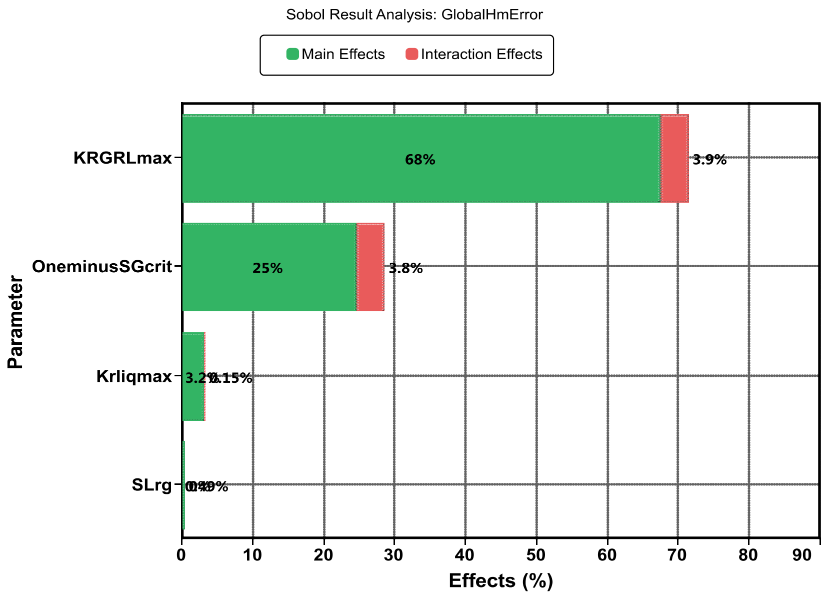

Fig 13.-Most influential parameter on objective function characterizing the error between model and well measurements

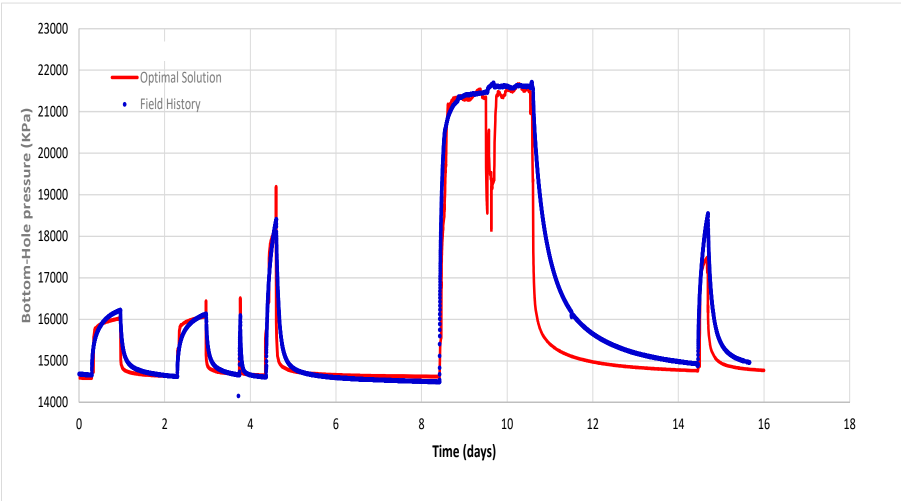

Fig 14.-Optimal history-matched bottom-hole pressure at the injection well HI during the single phase brine and two phase CO_2-brine injection periods

5.3 ANALYSIS OF RESULTS

During the injection tests, the CO_2 migrates about 80 meters away from the injection well as shown in figures 15 and 17. The impact in temperature is limited to the near wellbore region as shown in figures 16 and 17 due to thermal inertia of the reservoir rock. The pressure disturbance is extending further away from the injection well as shown in figure 17. The local pressure increase only extends as far as the CO_2 and relaxes quickly in the model. The pressure relaxation at the well (see figure 14) is always quicker than in the pilot. Consequently, there is still on-going work to match the current injection tests.

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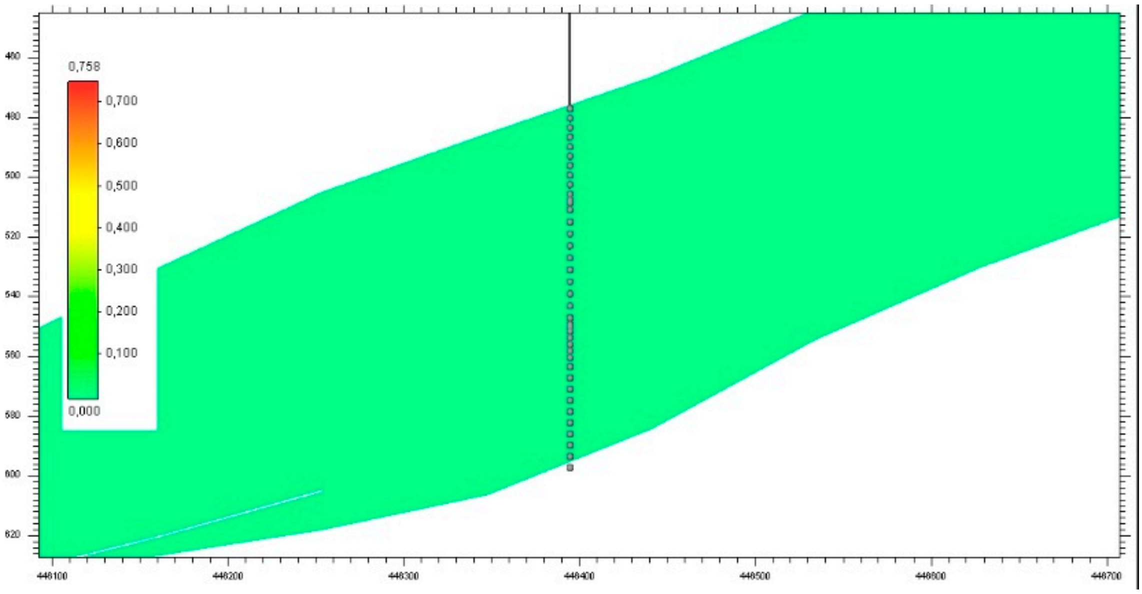

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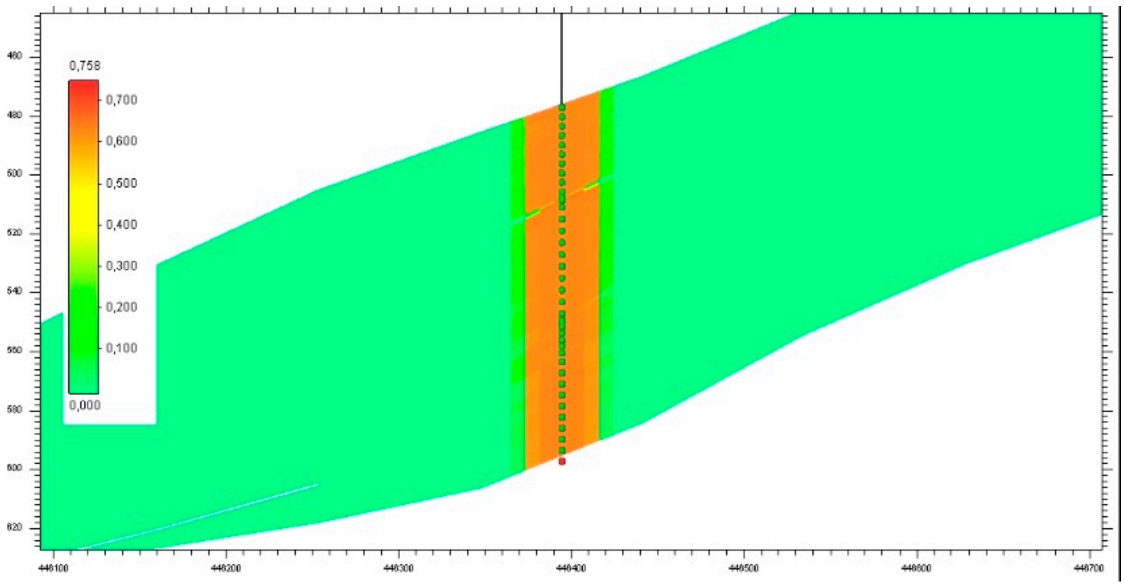

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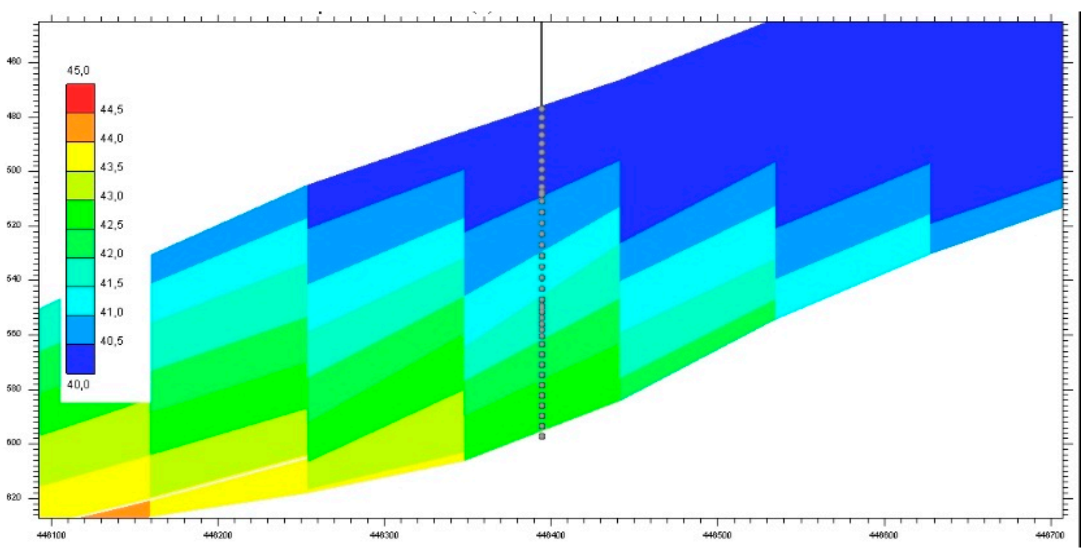
Fig 15.- Vertical cross-section of the time-evolution of CO_2 saturation in the fracture around the injection well HI during the two phase CO_2-brine injection periods



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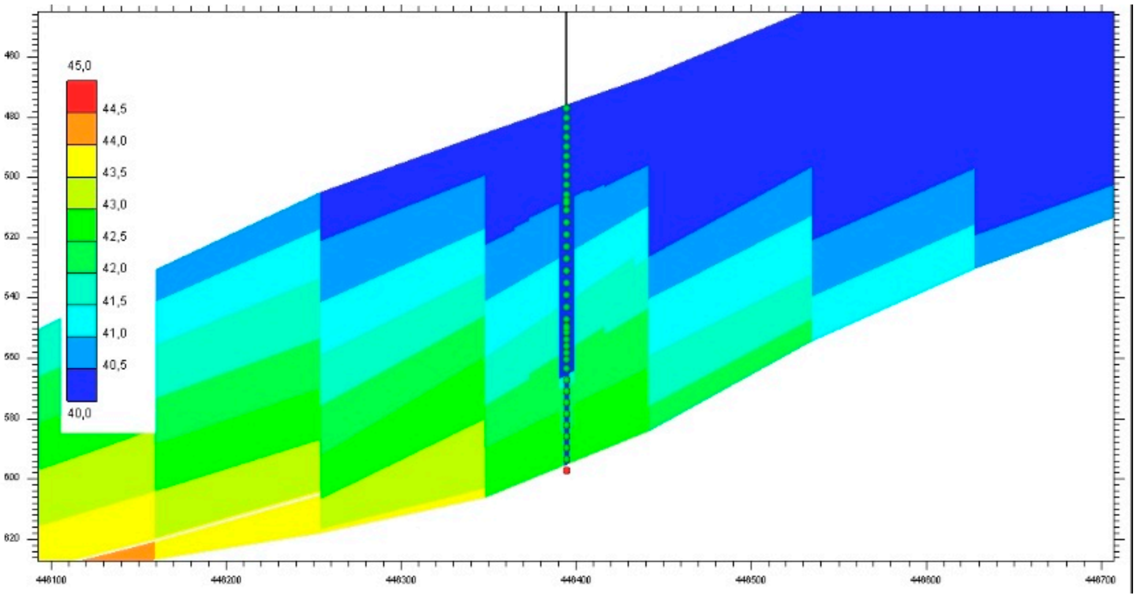
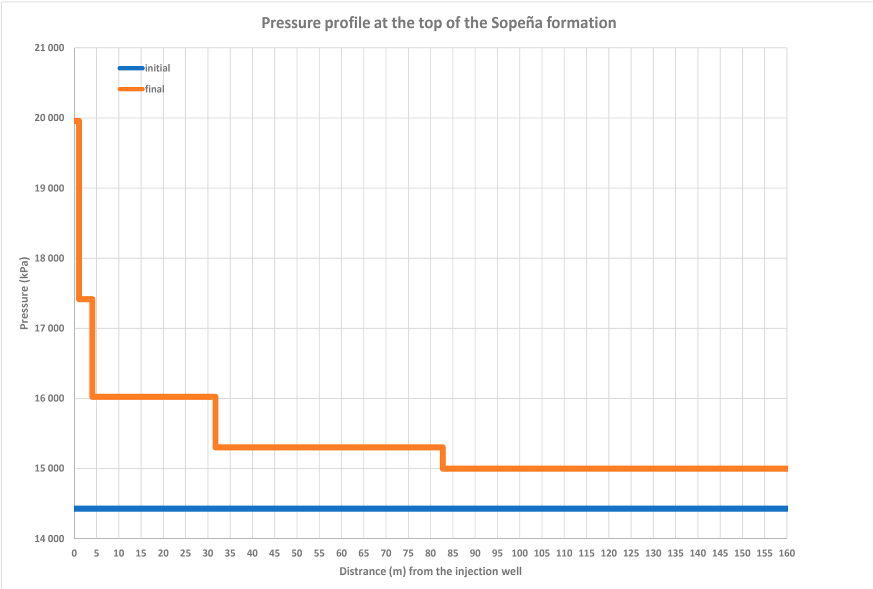
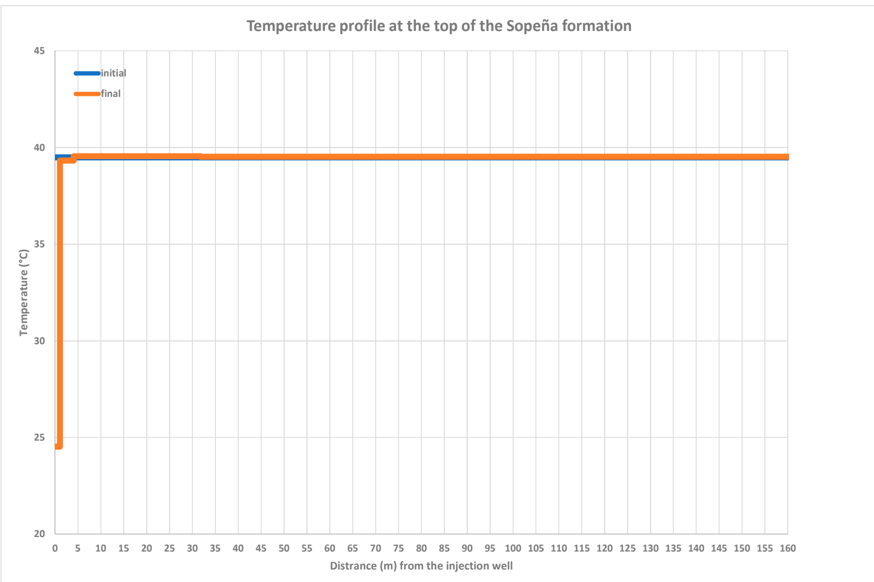


Final

Fig 16.- Vertical cross-section of the time-evolution of temperature in the fracture around the injection well HI during the two phase CO_2-brine injection periods





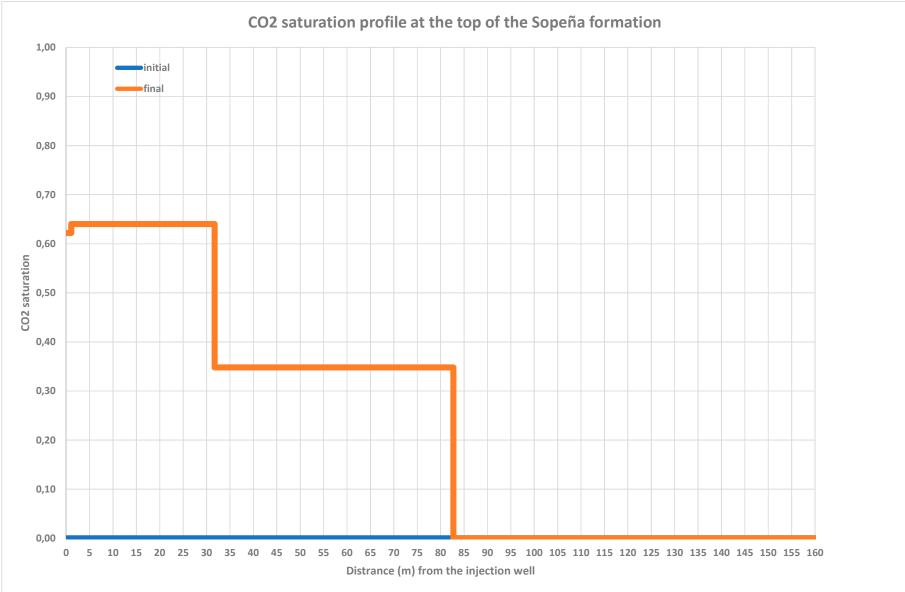


Fig 17.- Evolution of pressure (top), temperature (middle) and CO_2 saturation (bottom) profiles as a function of the distance from the injection well at the top of Sopeña formation

6 DISCUSSION AND FUTURE WORKS

As mentioned above, the injection tests conducted so far in Hontomín for ENOS project aim to better understand the fractured reservoir behavior in order to improve its hydrodynamic stability. Those ones conducted in pressure control mode revealed the decrease of injected flow to maintain constant the WHP value. On the other hand, tests conducted in flow control mode shown the pressure increases at the well head to hold a constant value of flow rate. The matter to discuss is if these results correspond to wellbore effects in the short term or they set a trend on long term behavior of pair seal-reservoir**.**

Something similar happens with the pressure recovery period during the reservoir fall-off phase, which plays a key role to determine the reservoir stability [Eiken O. et al., 2011]. The terms of BHP recovery depend on the injected fluid (brine/CO_2), due to different hydraulic properties of each one, and on the cumulative CO_2 injected on site. As happened in the study cases for the tests conducted in pressure and flow control modes described above, it is necessary to demonstrate if this recovery trend is due to short term effects occurred in the well vicinity or corresponds to the long term behavior of reservoir.

CO_2 injections were performed in liquid phase that is the most efficient operation. However, the injected fluids have cooled the pair seal-reservoir that could produce impacts that would put in risk the integrity of rock formations [Gor and Prévost 2013]. The heat transfer between the reservoir rock and the biphasic fluid needs to be investigated in order to test the viability of pair seal-reservoir for CO_2 storage [Somaye et al., 2010]. Particularly, the changes induced in geomechanics of rock massif and fractures must be studied to better understand the behavior of these reservoirs during the injection, preserving the seal integrity.

The modelling work was performed as an initial characterization work in order to tune the model to injection tests conducted during the hydraulic characterization phase [de Dios et al., 2017]. The model was based upon previous work [Le Gallo et al., 2017] and updated to account for a recent characterization of geological heterogeneities which was performed within ENOS project [Le Gallo and de Dios, 2018]. In order to account for the various operations and the geological context, the model was set up as a dual-permeability and porosity tacking into account the temperature effects and relative permeability hysteresis. The bottom-hole pressure match is quite satisfactory as shown in figure 14.

It is planned to perform continuous injections at Hontomín site during several days hereinafter to address all mentioned gaps, for gaining knowledge on the management of operational parameters to control the storage integrity for long term operations, and particularly, for setting of pressure recovery periods to ensure a safe re-start of injection. On the other hand, alternative strategies using cold CO_2 (temperature below 10ºC) will be designed and tested, with the aim of finding efficient operational parameters that are consistent with the safety of the process. As mentioned above, there is still on-going work to refine the modelling developed so far to investigate how the CO_2 plume migration and trapping mechanism will be.

7 CONCLUSIONS

Results from first injection tests conducted at Hontomín site within ENOS project confirmed the singularity of this reservoir where CO_2 migration is through the carbonate fractures. Thus, when pressure remains constant at well head with a value equal or higher than 75 bar for ensuring liquid injection, flow rate decreases considerably as CO_2 is expanding within the fracture network. On the other hand, when flow value is constant during injection the well head pressure highly increases as much CO_2 is injected on site.

As regards the period of time necessary for pressure recovery on the bottom hole during the fall-off phase, it depends on the injected fluid due to different hydraulic properties, and the cumulative amount of CO_2 existing on site.

Regarding the thermal profiles corresponding to injections, liquid CO_2 phase is ensured along the tubing which corresponds with an efficient operation, reaching fluid density values close to 0,83 t/m3 at the bottom hole.

The modelling performed so far shows a small lateral extension of the CO_2 away from the injection well during the injection tests with an even smaller extension of the temperature disturbance. As for most of the CO_2 storage projects in aquifers, the main impact is the extension of the pressure disturbance which drives the CO_2. The future modelling work shall focus upon the pressure fall-off periods which appears faster in the model than in the field.

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Sole responsibility lies with the authors, so the European Commission is not responsible for any use that may be made of the information contained in this article.

9 AUTHOR CONTRIBUTIONS

Dr. J.Carlos de Dios is Director of the Research Program for CO_2 Geological Storage in Fundación Ciudad de la Energía (CIUDEN) and member of the Management Board of ENOS project. He is responsible of the conceptualization of research activities conducted at Hontomín Technology Development Plant, and particularly to design the field test methodology and the corresponding investigation. Other of his responsibilities are the administration and supervision of the activities conducted on this site. He realized the visualization and writing-original draft of the manuscript.

Dr. Yann Le Gallo is the Operation Manager at Geogreen and partner of ENOS project. He is being responsible of formal analysis of Hontomín data from the site characterization in 2013, performing the modelling methodology. His contribution encompass the throughout modelling of Hontomìn site for static characterization of the fracture with FracaFlow™, geological modeling with Petrel™, dynamic multiphase characterization with GEM™ and uncertainty modeling with CMOST™

Dr. Juan A. Marín is the Head of Pilot Operations at Hontomín site. He is responsible of research activity planning, managing the resources to conduct the planned field tests on site. He also supervises the data curation, including the metadata production for initial use and later re-use and collaborates with the other authors in their interpretation.

10 GLOSSARY

- BHP.-Bottom hole pressure
- BHT.-Bottom hole temperature
- BRGM.-Bureau de Recherches Geologiques et Minieres
- CCS.-Carbon Capture and Storage
- DAS.-Distributed acoustic sensing system
- DTS.-Distributed temperature sensing system
- ENOS.-Enabling On Shore CO2 Storage in Europe
- EP Resolution.-European Parliament Resolution
- ERT.-Electric Resistivity Tomography
- HI.-Hontomín injection well
- HA.-Hontomín observation well
- INEA.-Innovation and Networks Executive Agency
- MD.-Measured depth
- P/T.-Pressure/Temperature
- WHP.-Well head pressure
- WHT.-Well head temperature

11 CONFLICTS OF INTEREST

The authors declare no conflict of interest. The founding sponsor had no role in the design of the study; in the collection, analyses, or interpretation of data; in the writing of the manuscript, and in the decision to publish the results.

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