Corrective measures based on pressure control strategies for co2 geological storage in deep aquifers

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CORRECTIVE MEASURES BASED ON PRESSURE CONTROL STRATEGIES FOR CO2 GEOLOGICAL STORAGE IN DEEP AQUIFERS

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Abstract

A prerequisite to the wide deployment at an industrial scale of CO_2 geological storage is demonstrating that potential risks can be efficiently managed. Corrective measures in case of significant irregularities, such as CO_2 leakage, are hence required as advocated by the recent European directive on Carbon Capture and Storage operations. In this regard, the objective of the present paper is to investigate four different corrective measures aiming at controlling the overpressure induced by the injection operations in the reservoir: stopping the CO_2 injection and relying on the natural pressure recovery in the reservoir; extracting the stored CO_2 at the injection well; extracting brine at a distant well while stopping the CO_2 injection, and extracting at a distant well without stopping the CO_2 injection. The efficiency of the measures is assessed using multiphase fluid flow numerical simulations. The application case is the deep carbonate aquifer of the Dogger geological unit in the Paris Basin. A comparative study between the four corrective measures is then carried using a cost-benefit approach. Results show that an efficient overpressure reduction can be achieved by simply shutting-in the well. The overpressure reduction can be significantly accelerated by means of fluid extraction but the adverse consequences are the associated higher costs of the intervention operations.

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1. Introduction

CO_2 capture and geological storage (denoted "CCS") is seen as a promising technology to achieve large reduction in atmospheric greenhouse gases emissions. In the portfolio of options, geological storage in deep saline aquifers is recognized to offer a very large potential storage capacity (IPCC, 2005). But, a prerequisite to its large-scale implementation is demonstrating its safety (IEA GHG, 2007a). In this regard, it is of paramount importance that operators not only understand the risks but also correctly manage them. Managing risks implies knowing "what can be done" in case of abnormal behaviour and, in practise, means having intervention plans composed of a full set of preventive measures, corrective measures and remediation measures that are able to mitigate any significant irregularity.

Concerning preventive measures, there have been a lot of progress recently that can be found in the literature: well design requirements (Cailly et al., 2005), improvement of the trapping efficiency (Ide et al., 2007, Leonenko et al., 2008, Nghiem et al., 2009, Qi et al., 2009), or management of the overpressure (Lindeberg et al., 2009). Developments in the field of corrective measures for CO_2 storage reservoirs still remain limited. Yet, in the directive of the European Commission on CO_2 storage (European Commission, 2009), issued in April 2009, it is stated that the storage permit shall contain the approved corrective measures plan (Article 9, paragraph 6). According to this directive, corrective measures mean "any measures taken to correct significant irregularities or to close leakages in order to prevent or stop the release of CO_2 from the storage complex". Developing robust corrective measures and protocols is all the more important and urgent since large scale pilot plant of CCS are planned to be implemented in the near future, as called by the Zero Emission Platform (ZEP, 2008).

Besides, such available best practices will help to build confidence and public acceptance in this technology.

Corrective measures mainly stem from the past efforts in the activities of oil and gas industry. Reviews of such measures can be found in Benson and Hepple (2005), Perry (2005) and IEA-GHG (2007b). However, the extent to which such intervention practices can be used for CO_2 geological storage in deep saline aquifers should be assessed, given the uniqueness of CO_2 geological storage, both in terms of time scale and specificity of the injected gas. The mutual efficiency of the measures should also be compared against each other. Considering the classical "source – transfer – target" risk management approach (e.g. UK DOE, 1995), the objective of the present paper is to investigate corrective actions controlling the "source" component i.e. from the reservoir itself. In this paper, we will focus on an intervention strategy relying on the pressure control of the deep saline aquifer reservoir. The importance of such an aspect can be understood from a physical point of view. CO_2 is injected at the supercritical state and due to the density contrast with the host reservoir brine, CO_2 may naturally escape from the reservoir through any high permeable (e.g. faulty) zones or artificial pathways (e.g. abandoned wells) and the pressure induced by CO_2 injection operations can be considered an additional driving force to the natural buoyancy force. Considering hydrogeologic aspects, the large scale impact of CO_2 injection operations (large-scale fluid pressurization and migration of native brines, see Birkholzer et al., 2009 and Yamamoto et al., 2009) is directly linked to the combining effects of the pressure buildup and the area of review, which are induced by CO_2 injection operations. The area of review is the surrounding region of the storage site that may be impacted by the injection activity (EPA, 2008). For instance a zone in a given geological formation where the pore pressure is modified by the injection of CO_2, is considered within the area of review. Furthermore, reservoir pressure is a key aspect for the assessment of the caprock integrity (e.g. Rutqvist et al., 2007).

Note that other intervention strategies may be proposed such as strategies based on the improvement of the CO_2 trapping either through dissolution phenomena (Leonenko et al., 2008) or through residual trapping (Nghiem et al.,2009, Qi et al., 2009). However, such methods still require further developments protocols, which are beyond the scope of the present paper and we chose to focus on conventional and commonly used reservoir engineering technologies.

The efficiency of the proposed measures is addressed using numerical simulations with an application in the Paris basin case (Grataloup et al., 2009). The comparison is undertaken following a cost-benefit approach and provides key aspects that should be considered for developing robust best practices of large scale CO_2 storage projects.

2. Model setup and parameters

The carbonate Dogger aquifer is a potential site for CO_2 geological storage in the Paris basin (Grataloup et al., 2009) and is used as an application case for the intervention strategy (see section 3). An industrial-scale injection rate is considered reaching 1 million tonnes of CO_2 per year (32 kg/s) using a single injection well. This annual rate approximately represents the CO_2 rate captured from a medium-size coal-fired power plant and is close to the annual rate injected at the CO_2 storage field of Sleipner (Hoem, 2005).

Geometry and boundary conditions

The aquifer layer is assumed to be of very large radial extent (over 150 km) and is represented by a 2D-layer horizontal model. The system considers one layer with a thickness of 40 m. The grid includes of a fine meshed zone (zone A) of 200 x 200 cells of equal size (75mx75mx40m in the x, y, and z direction respectively) and a coarse meshed zone (large volume cell) at the boundary of the model (zone B, see Figure 1). A no-flow condition is assigned to lateral boundaries and the system is considered

closed with no exchange of fluid or heat with the upper and lower layers. Injection occurs in one element located in the centre of the zone A.

[Figure 1 about here]

An axisymmetric model equivalent to the 2D layer model was also used with a mesh refinement in the injection zone. The injection well element has a radius of 30 cm and subsequent cells have a logarithmically increasing radius. The model is composed of 4 layers in the vertical direction of 10 m each. The 2D-layer model was used for the base case while the axisymmetric model was used to test assumptions (see Discussion in section 5).

Aquifer properties and initial conditions

Homogeneous and isotropic properties are assigned to the aquifer, using average values based on Rojas et al. (1989) and Andre et al. (2007) (see Table 1). The mean porosity is 15 % and the intrinsic permeability is assumed to be spatially homogeneous at 150 mD. Capillary pressure model is assumed to follow the van Genuchten's formulation (van Genuchten, 1980), whereas the relative permeability model is described by the van Genuchten-Mualem formulation (Mulaem, 1976; van Genuchten, 1980). Initial temperature and pressure conditions respectively reach 80 °C and 173 bars. Salinity in the Dogger reservoir ranges from moderate (5 g of NaCl per 1000 g of water in the Southern part of the basin, Rojas et al., 1989, Andre et al., 2007) to high values (about 30 g of NaCl per 1000 g of water in the Eastern part of the basin, Rojas et al., 1989, Andre et al., 2007). The model was homogeneously assigned a mean value of 15 g of NaCl per 1000 g of water.

Numerical modelling

Numerical simulations are performed using the multi-phase, multi-component transport simulator TOUGH2 (Pruess et al. 1999); with the ECO2N Equation of State (Pruess,

2005), which takes into account the thermodynamic and thermophysical properties of water–NaCl–CO_2 mixtures. The problem is assumed to be isothermal. Model parameters and aquifer hydrogeologic properties are summarized in Table 1.

[Table 1 about here]

With these properties, we can calculate a gravity number. Following the definition of Ide et al. (2007), we have:

$$N_{gv} = \frac{k_v L \Delta\rho g}{Hu\mu_{brine}} \quad (1)$$

where k_v is the vertical permeability, L/H is the shape factor, $\Delta\rho$ the density difference, g the acceleration of gravity, u the total average Darcy flow velocity, and μ_{brine} is the viscosity of brine.

According to the simulations, we have L/H ≈ 50 and u ≈ $1{,}1.10^{-5}$ $m.s^{-1}$. With densities and viscosity obtained from the correlations used in the ECO2N equation of state (Pruess, 2005), we get $N_{gv} \approx 8.5$, which is situated in the low N_{gv} range according to Ide et al. (2007). Thus, the movement of the CO_2 plume in the horizontal direction will more depend on viscosity forces than on gravity forces. This rapid calculation shows that the assumption of only one horizontal layer in our model is valid for the reservoir simulated.

3. Intervention strategy

Methodology

We propose an intervention strategy based on reservoir pressure control. When injecting in an aquifer, CO_2 remains mainly at a supercritical state and displaces the resident brine to occupy pore space. As a result, pressure in the reservoir increases. We define the overpressure as the difference between the initial (of 173 bars) and the final reached pore pressure. In this paper, the area of review is defined as the area where the overpressure is higher than 5 bars. Figure 2 shows the overpressure and the area of review after 10 years of injection.

[Figure 2 about here]

The overpressure magnitude near the wellbore reaches more than 40 bars at the end of the injection and the area of review is more than 20 km.

In the view to both control the overpressure magnitude and the area of review of the overpessurized zone, we propose to investigate four main corrective measures, which are as follows:

- Corrective measure n°1: stopping injection;
- Corrective measure n°2: producing at the "injection" well;
- Corrective measure n°3: producing with a distant well and stopping the injection.
- Corrective measure n°4: producing with a distant well without stopping the injection.

The overpressure reduction is taken as a metric for the corrective measure efficiency. To consider the spatial component, efficiency is assessed defining the two following scenarios:

1. After 10 years of injection at 1Mt/year, the operator aims at lowering the pressure in the injection zone (Scenario n°1).
2. After 10 years of injection at 1Mt/year, the operator aims at lowering the pressure 3km away from the injection well (Scenario n°2).

Each intervention lasts for 1 year. This is to be compared with the typical time duration of an industrial scale project which is expected to range between 30 and 50 years. In case of a significant irregularity, such as leakage from the reservoir, the authority could decide to definitely close the site, if the operator does not manage to permanently close the leak. The time duration of 1 year hence appears to be feasible and financially acceptable regarding the time scale of an industrial CO_2 storage project.

Corrective measure n°1: Stopping injection

When a significant irregularity (leak, upper aquifer pore pressure increase, unexpected extension of the CO_2 plume, etc) is detected by the operator through the monitoring system in place, a simple measure consists in shutting down the injection process. A monitoring well equipped with a downhole pressure gauge located in a formation above the storage reservoir could detect for instance pressure changes as low as 0,007 bars under favourable conditions (Benson et al. 2006). In particular; the permeabilities and thickness of the formation, the position of the monitoring well and the natural background fluctuations are the more important parameters that determine such conditions. Alternatively, indirect monitoring methods could be used, such as seismic methods, electromagnetic methods or tilt measurements methods (used to measure the land-surface deformation). Taken separately or together, these measurements can be inverted to provide subsurface pressure changes (Benson et al. 2004). After the shut-in of the well, we focus the study on the medium term behaviour of the pore pressure evolution. We define medium term as the timescale corresponding to the length of operations (several decades). For long term evolution of the plume after the closure of operations (corresponding to several centuries), see Zhou et al. (2005).

The results are shown in Figure 3.

[Figure 3 about here]

In Figure 3, the overpressure is represented as a function of the radial distance from the injection well. Considering both scenarios, we show that the overpressure rapidly drops in the injection zone, whereas a significant overpressure decrease 3 km away from the injection zone is only observed after 1 month.

A useful piece of information for risk management is the assessment of the required time duration for the overpressure to drop below a given threshold (Figure 4). We chose a threshold of 5% reduction of the overpressure. Hence, Figure 4 shows that in

order to achieve overpressure reduction by 5% 3 km away from the injection well, a time duration of more than 100 days is necessary. Note that the graph is separated into 2 parts. The first part presents a parabolic form and corresponds to the radial extent of the CO_2 plume, whereas the second part is nearly linear and represents the brine saturated zone. After one year, the pressure reduction does not reach the limit of the area of review which is approximately 20 km away from the injection well.

[Figure 4 about here]

Figure 5 gives the overpressure evolution over time for both scenarios (injection zone and 3km away from the injection zone).

[Figure 5 about here]

This analysis shows that the overpressure reduction is quick, with a strong pressure reduction in the first few days in the injection zone from $\Delta P0=42$ bars to $\Delta P1=14$ bars, corresponding to a reduction of nearly 30 bars. At 3 km from the injection zone, the overpressure reduction is only observed after a minimum time duration of 50 days, from $\Delta P0=14$ bars to $\Delta P1=10$ bars, corresponding to a reduction of nearly 4 bars.

Corrective measure n°2: Producing at injection well

To accelerate the pressure reduction, converting the injection well to a producing well may be envisaged. For an intervention period of 1 year, we propose the following protocol: (1) production phase at the injection well for 6 months, and (2) observation during 6 months. For simplification purpose, the well is producing at a constant rate which is equal to the injection rate (~ 1Mt/year). This is in the order of magnitude of a typical geothermal pump (CFG Services, personal communication) reaching 32 kg/s (115 m^3/h).

Figure 6 shows the comparison between measure n°1 and n°2 in the injection zone and at 3 km from the injection zone. During the extraction, pressure in the injection zone declines. When the extraction stops, the pressure field is equilibrated in the

reservoir leading to a pressure recovery in the injection zone. The pressure reduction after intervention time of 1 year reaches nearly 35 bars from ΔP0 = 42 bars to ΔP1 = 8 bars. For the second scenario, pressure reduction is more significant as well, with a larger effect compared to the "stopping" measure. Pressure reduction reaches about 6 bars, from ΔP0 = 14 bars to ΔP1 = 8 bars.

[Figure 6 about here]

Corrective measure n°3: Extracting with a distant well

If the abnormal behaviour is detected outside the injection zone, pressure should be lowered in the region at risk. Let us consider that the region at risk is located at 3 km away from the injection zone. A measure relying on fluid production at this distance can be envisaged. In practise, an observation well may be present at this distance and can be converted into a production well provided that the well completion presents the appropriate requirements (McPherson, 2008). In the studied case, the CO_2 plume at the end of the injection period has a lateral extension superior to 2 km, as depicted in the Figure 3, in which the extent of the plume corresponds to the slope discontinuity on the curves. Produced fluid composition is composed 100% of brine (see discussion in section 5). Figure 7 shows the results for this simulation.

[Figure 7 about here]

As in the previous measure, production occurs for 6 months at the same rate (~1Mt/year), followed by a 6 months observation phase. Injection is stopped during the period of intervention (1 year). After the production period, pressure reaches an acceptable threshold, but this shows little improvement in terms of pressure reduction compared to corrective measures n°1 and n°2. The overall pressure reduction reaches 29 bars (from ΔP0 = 42 bars to ΔP1 = 13 bars) in the injection zone, whereas it only reaches 5 bars (from ΔP0 = 14 bars to ΔP1 = 9 bars) 3 km away from the injection zone.

Corrective measure n°4: Extracting with a distant well without stopping the injection

In the previous measure, we decided to stop the injection during the 1 year intervention period, but there is still the possibility to continue injection operations during the intervention. This intervention action is proposed, as a preventive measure, by Lindeberg et al. (2009). Results are shown in the Figure 8.

[Figure 8 about here]

Production only presents a slight effect on both scenarios. Simulations show a pressure reduction of 2 bars for the first scenario and 1 bar for the second scenario. More significant effects are expected if the measure is applied during the whole length of the operations (Lindeberg et al. 2009), but no clear conclusion can be drawn for its efficiency as a corrective measure.

4. Comparative study of the corrective measure

The different corrective measures are compared using a cost benefit approach. We define "benefits" in terms of overpressure reduction between the beginning of the intervention (i.e. at the end of the 10 years injection period) and the end of the intervention, after 1 year. We define "costs" in a qualitative manner, in terms of volume of CO_2. The cost of 1t of CO_2 can be converted into economic value based on the quotas price in the Emission Trading System (ETS, see European Commission, 2003). Costs related to the logistics of the intervention operations are underlined without indicating quantitative financial values. Table 2 summarizes the results.

[Table 2 about here]

Considering the first measure, the cost reaches 1 Mt of CO_2. This represents the amount of CO_2 that could not be stored because of the intervention.

Considering the second measure, costs reach 1.5 Mt of CO_2, which consists of 1 Mt that could not be stored and of 0.5 Mt that were extracted during 6 months. We show that benefits for both scenarios are larger too. Although this measure appears unproductive, it is often considered as the ultimate corrective measure (Benson and Hepple, 2005, IEA-GHG, 2007b): if the reservoir is found to be inappropriate for the definitive containment of CO_2, then it will have to be back produced partially or totally. For a study of the feasibility of such a measure at a long term, refer to Akervoll et al. (2009).

Considering the third measure, additional costs are 1 well required for the production and 0.5Mt of brine production. As stated earlier, the operator could use an existing observation well and convert it into a production well. The economic costs would be highly reduced. Conversely, the operator would need to drill an additional well, hence implying a large financial cost. IEA-GHG 2007b indicates an average value of 2.5 M$, but this is highly dependent on the depth, on the stratigraphy of the area and on the availability of a rig. Besides, note that intervention time of the corrective measure should then include the time duration for the additional wellbore to be drilled. Provided that 6 months of drilling operations are required, this means that the intervention will only starts 6 months after the significant irregularity has been observed. The brine produced is also considered a cost, as treatment and storage facilities are required at the surface. In most countries, regulations do not allow the operator to release the brine in the nature. If the storage is located offshore, then one solution is to obtain a permit in order to release the brine directly into the sea. According to Lindeberg et al. (2009), this is not an issue provided that the brine does not contain high concentrations of solids. If the storage is onshore, the operator could inject the brine in another reservoir, but this would require an authorization from the regulating authorities and could require feasibility studies. The ratio benefit/cost of this corrective measure is not necessarily high but it is interesting to note that even by producing at a distant well,

effects are more significant in the injection zone compared to measure n°1 "stopping injection". Besides, measure n°2, "extracting at the injection well", presents a better effectiveness in terms of pressure reduction for both localisations (in the injection zone and at 3 km) compared to measure n°3 "extracting at a distant well".

Considering the fourth measure, for which brine is produced while CO_2 injection continues, costs remain limited, as injection operations are not stopped, whereas benefits appears to be limited as well.

5. Discussion

The 2D-layer model used for the results was necessary for a comparison between the measures, but it relies on assumptions which might have an influence on the results. In this view, a 2D-axisymmetric model was also used.

The first limitation of the model is the modelling of the injection represented by a coarse 75m large grid cell. Comparison between both models through numerical simulations shows a difference not larger than 5% for the evolution of the overpressure near the wellbore. Further works should be undertaken using for instance a Local Grid Refinement (LGR) around the wellbore (Audigane et al. 2009).

The second limitation is to neglect gravity effects along the thickness of the reservoir, which influence the results of the simulations of corrective measure n°2. At the end of the injection period, CO_2 tends to accumulate atop of the reservoir, driven by the buoyancy effect (Figure 9a). When extracting from injection well in scenario 1, CO_2 located at the bottom of the reservoir will be removed first, and a water breakthrough might occur (extraction of water along with the CO_2). By neglecting the gravity effect in the reservoir, we then supposed that when extracting at the injection well for 6 months, the produced fluid would be pure CO_2. Simulations using the 2D-axisymmetric model, thus taking into account the gravity effects, showed that this assumption was valid in the considered case. After one year of extraction at the same rate (1Mt/yr), only CO_2

was extracted. Figure 9b shows the CO_2 saturation inside the reservoir after one year of extraction. CO_2 is still present around the wellbore along the thickness of the reservoir. Besides, note that CO_2 present a larger mobility than brine. The calculated gravity number for this case of about 8.5 also confirms that there would not be a significant gravity tongue and that the production of brine through the injection well should not be an issue. However, for longer period of extraction, a more refined model around the well, with more vertical layers would be appropriate.

[Figure 9 about here]

Another element in this discussion would be the use by the operator of a more elaborated well completion that would allow the extraction of CO_2 at several desired depths and the extraction or even the simultaneous injection and extraction of CO_2 at different depths.

In this paper, we choose the reduction in overpressure at predefined zones as a metric for effectiveness assessment of the corrective measures, but the evolution of extension of the area of review can also be considered an alternative metric. To study such an evolution using the 2D-layer model might present limitations, as the lateral extension of the area of review at the end of injection is approximately 20km (Figure 2), thus corresponding to zone B in the model (Figure 1) i.e. the coarse meshed zone of the model. For the intervention time duration considered in this study (only 1 year), effects on the area of review of the selected corrective measures are not expected to be significant, as depicted in Figure 4 showing that the pressure reduction front only reach 15 km after one year, but improvements of the model (e.g. grid refinement optimization approach) should be achieved considering larger intervention time durations.

6. Concluding remarks and further works

In this study four different corrective measures based on reservoir pressure control for the geological storage of CO_2 in deep aquifers are compared using a unique 2D-layer

model. A first simple corrective measure is stopping injection and relying on the natural pressure recovery in the reservoir. This study shows that this measure presents a good effectiveness in case of a momentary safety problem, even in areas outside the CO_2 plume zone. Corrective measure relying on active transfer control through the production of fluids from the reservoir, whether at the injection well or at a distant well, could accelerate the pressure reduction process, but the costs associated with such measures are larger as well. Producing brine at a distant well while injecting CO_2 only has a small potential for pressure reduction in the short term. But this measure may show a better efficiency in the long term compared to alternative measures. The undertaken comparison following a cost-benefit approach provides basic understanding to support the development of robust best practices of large scale CO_2 storage projects as required in the recent regulation frameworks on CCS operations. Further research efforts are thus required in the field of corrective measures in the view of a wide deployment of CCS at an industrial scale. This should take into account the long term behaviour, particularly during the post-closure phase of the storage project, the combination of different corrective measures, the definition of more complex injection/extraction well configurations and the influence of the spatial variability of the model parameters at a basin scale.

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List of Figure Captions

Figure 1: Schematic of the model used. 2D-layer model. Zone A: 200 x 200 square cells with a width of 75m each. Zone B: 6 large cells, which radii follow a logarithmic progression.

Figure 2: Overpressure (bars) in the reservoir after 10 years of injection. The largest circle represents the area of review defined for a pressure cut-off at 5 bars.

Figure 3: Evolution of the overpressure around the wellbore after the shut-in of the CO_2 injection well

Figure 4: Spreading of the pressure diminution front in the reservoir

Figure 5: Measure n°1: Evolution of the overpressure over time after the shut-in of the CO_2 injection well in the injection zone and at 3 km from the injection zone

Figure 6: Measure n°2: Evolution of the overpressure in the injection zone and at 3 km from the injection zone. The marked line shows the overpressure evolution for the corrective measure n°1.

Figure 7: Measure n°3: Evolution of the overpressure in the injection zone and at 3 km from the injection zone. The marked lines show the overpressure evolution for the corrective measure n°1.

Figure 8: Measure n°4: Evolution of the overpressure in the injection zone and at 3 km from the injection zone without stopping injection and comparison with the evolution of the overpressure without intervention (injection continues).

Figure 9: Measure n°2: Evolution of the CO2 saturation in the 2D-axisymmetric model. Top: At the end of injection. Bottom: After one year of extraction. There is no evidence of water breakthrough at the bottom of the production borehole.

List of tables

Parameters	Mean value
Intrinsic permeability [mD]	*150*
Porosity [%]	*15*
Thickness [m]	*40*
Injection depth [m]	*~ 1750*
Initial temperature [°C]	*80*
Initial pore pressure [MPa]	*17,3*
Salinity [% wt.]	*1.5*
Injection rate [Mt/yr]	*1*
van Genuchten m	*0.457*
Residual liquid saturation [%]	*20*
Residual Gas saturation [%]	*5*
van Genuchten P_0 [Pa]	*5.4e4*

Table 1: Model parameters and aquifer hydrogeologic properties

Measures	**Benefits**		**Cost**
	Scenario 1 (in the injection zone)	**Scenario 2 (at 3km from the injection zone)**	
Stopping injection	65%	30%	1Mt CO_2
Producing at injection well	80%	45%	1.5Mt CO_2
Extracting with distant well	70%	35%	1Mt CO_2+1 well+0.5Mt brine
Extraction with distant well while injecting	5%	7%	1 well+0.5Mt brine

Table2: Comparative study of the corrective measures based on a cost-benefit analysis

Figure 1

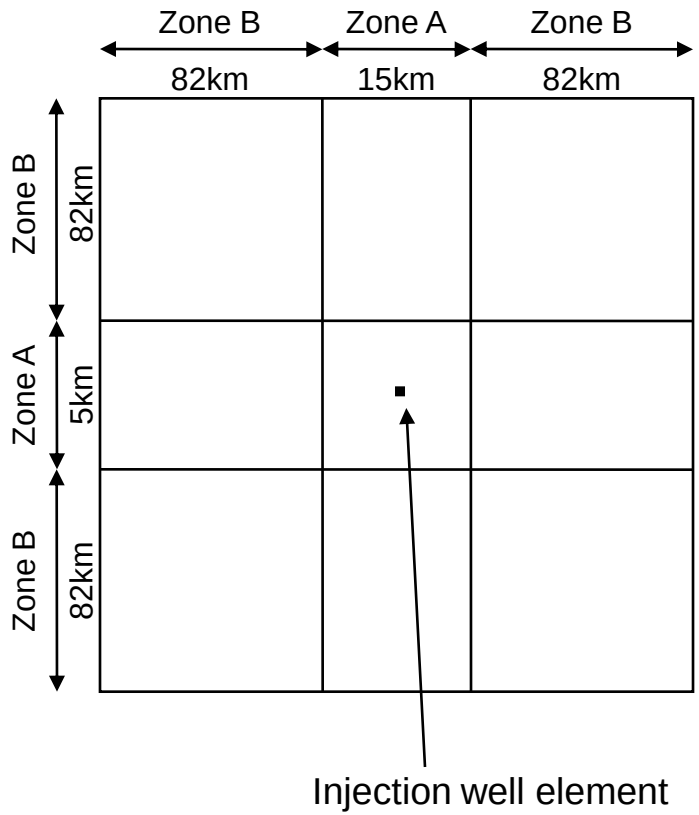
Zone B
Zone A
Zone B
82km
15km
82km
Zone B
82km
Zone A
5km
Zone B
82km
Injection well element

Figure 2

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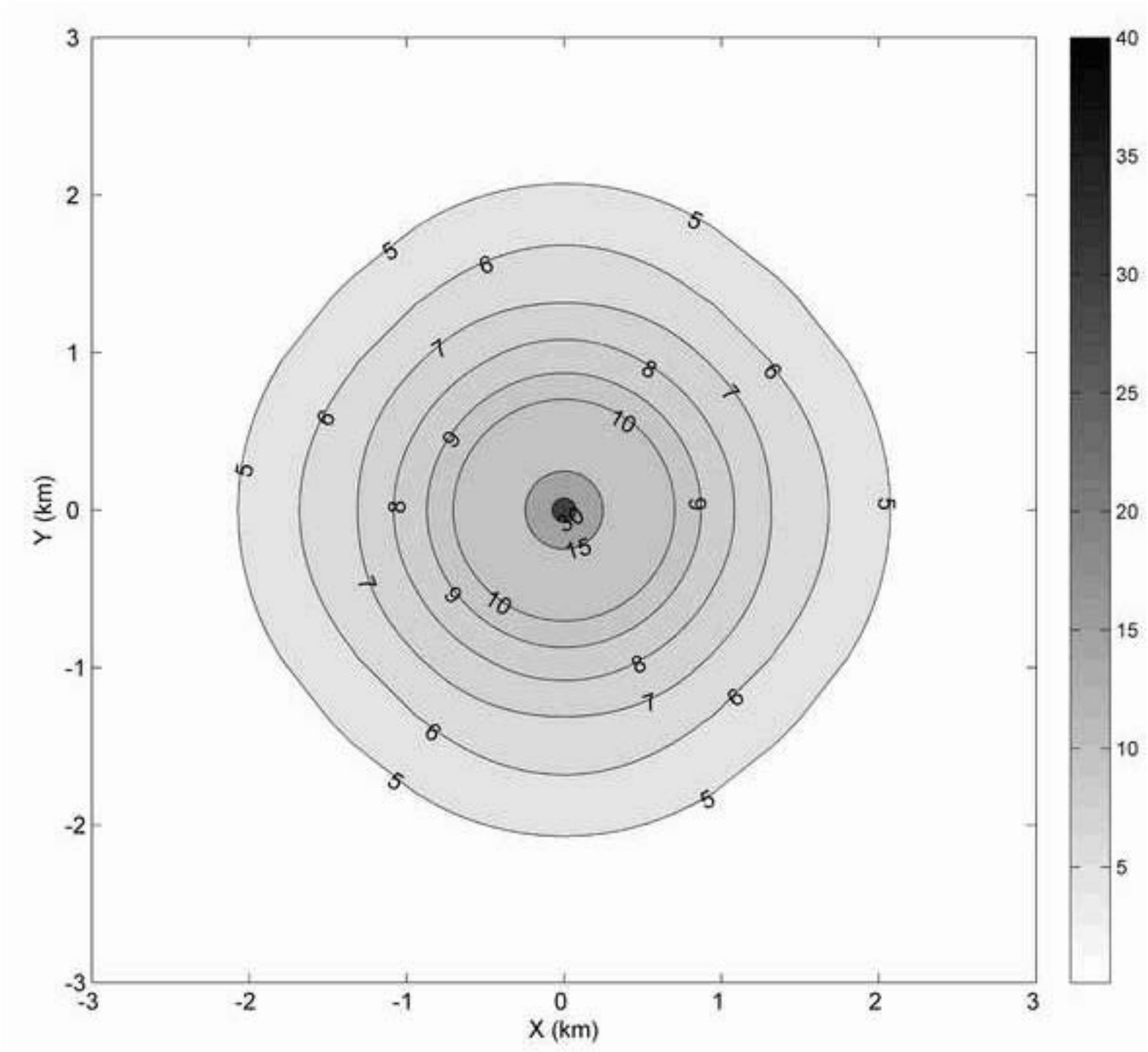

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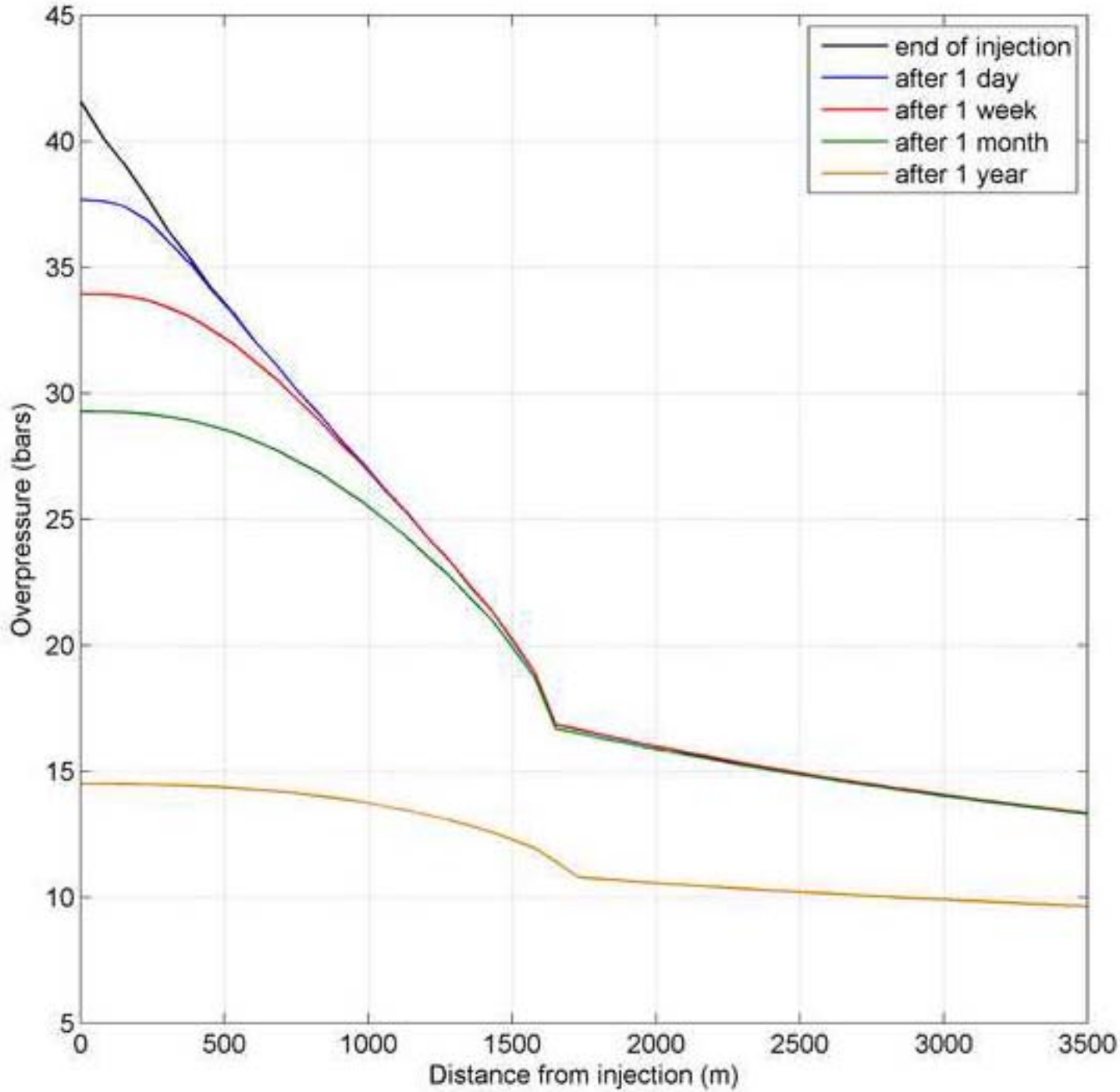

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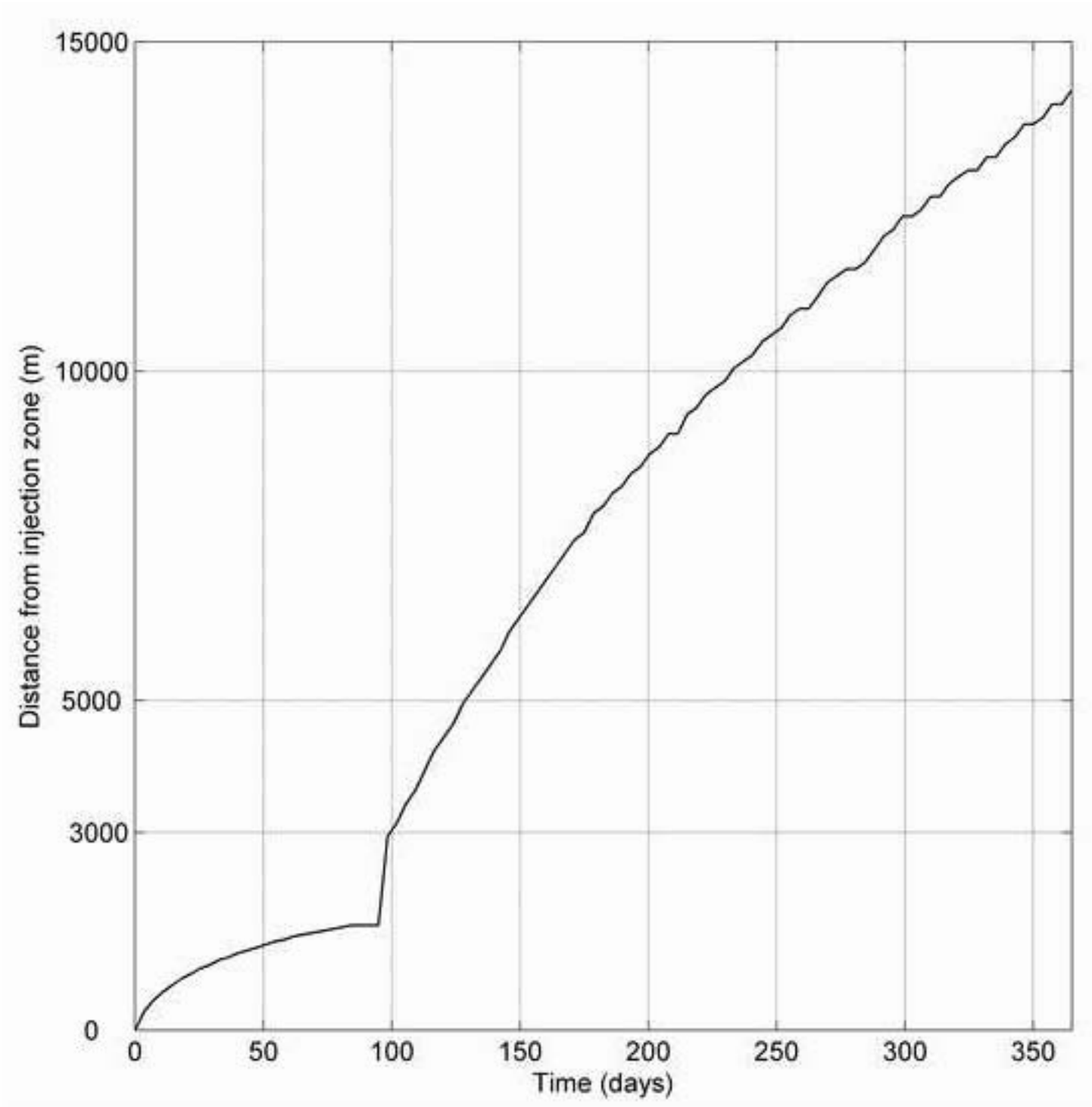

Figure 5
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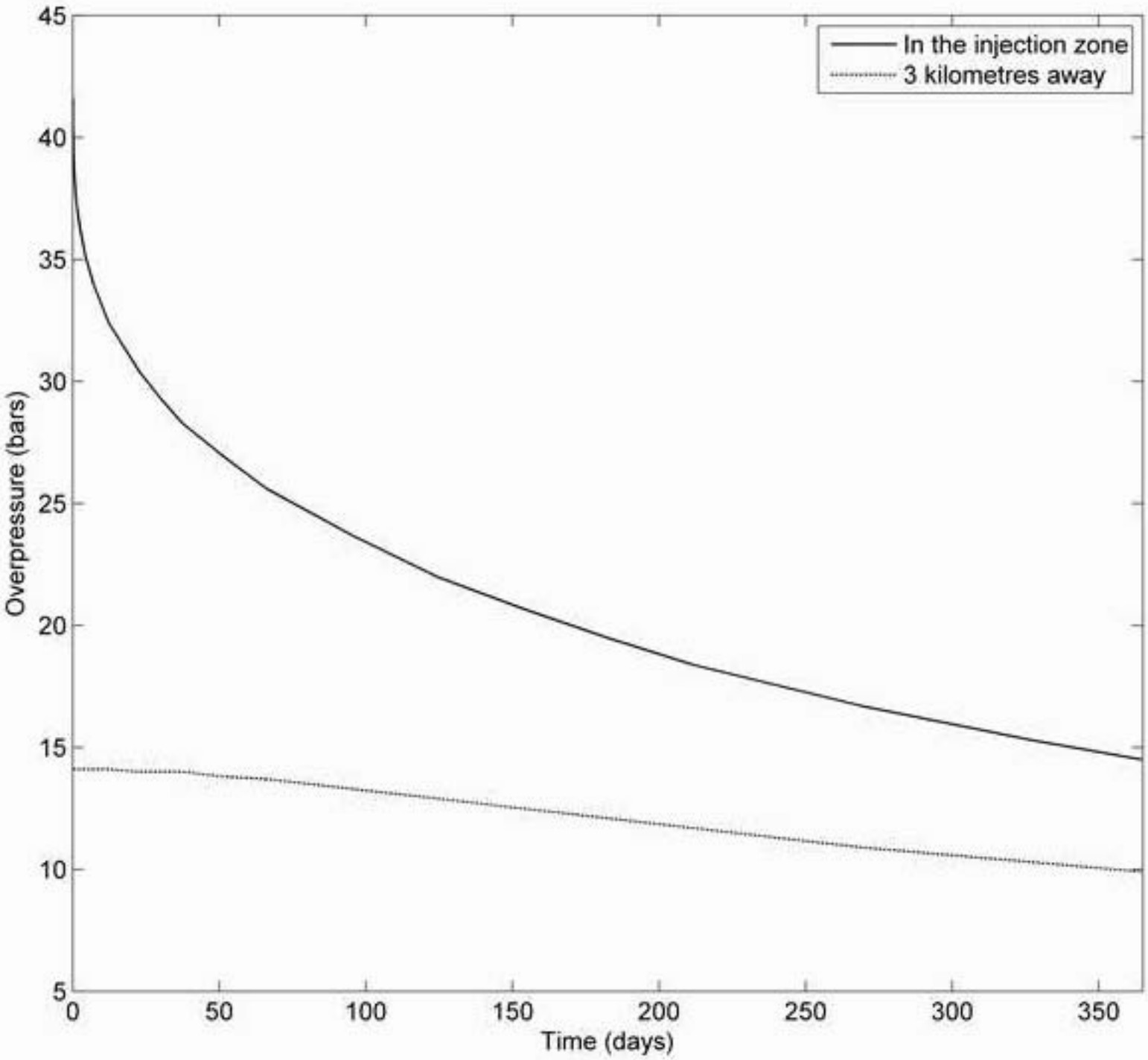

Figure 6
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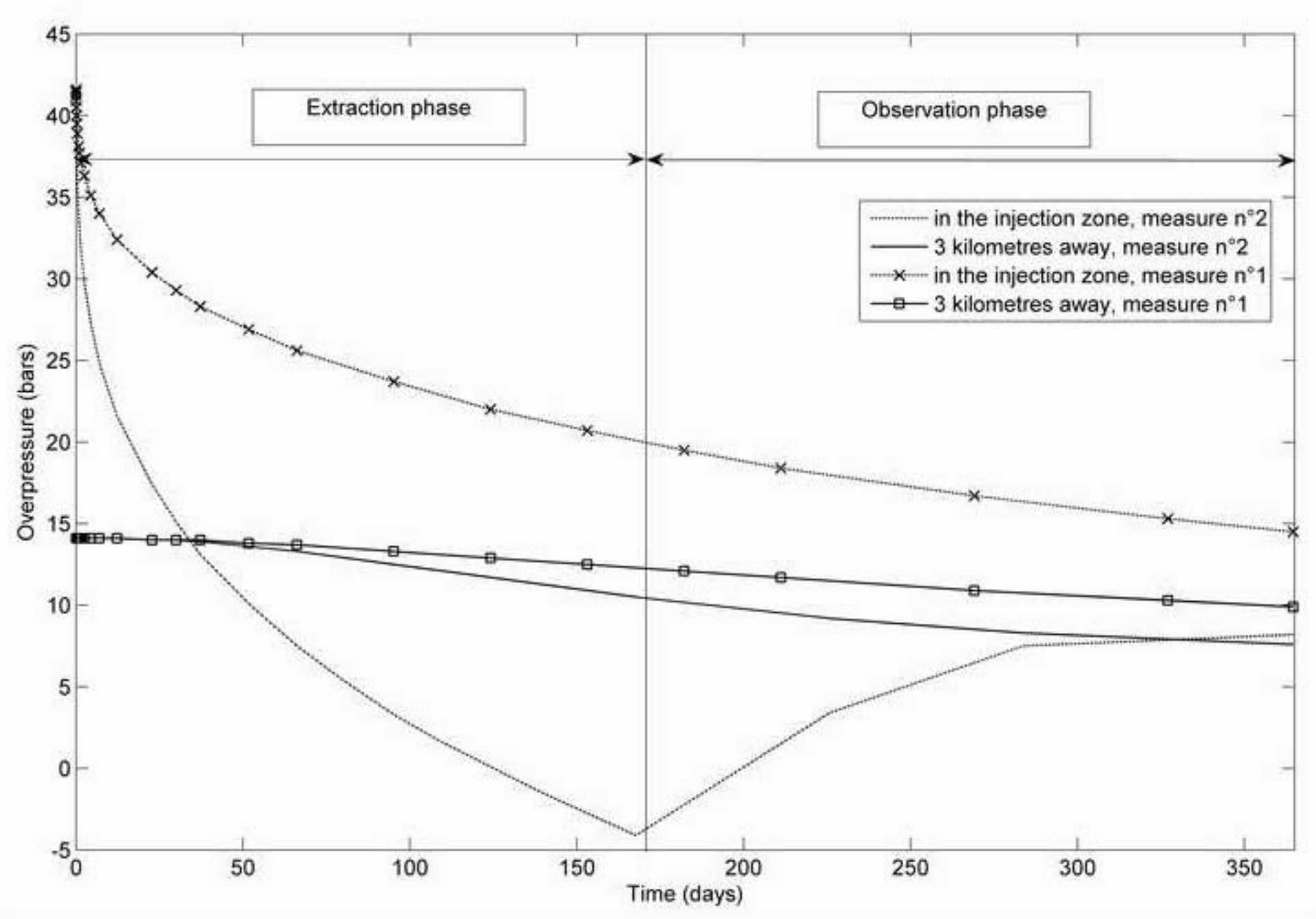

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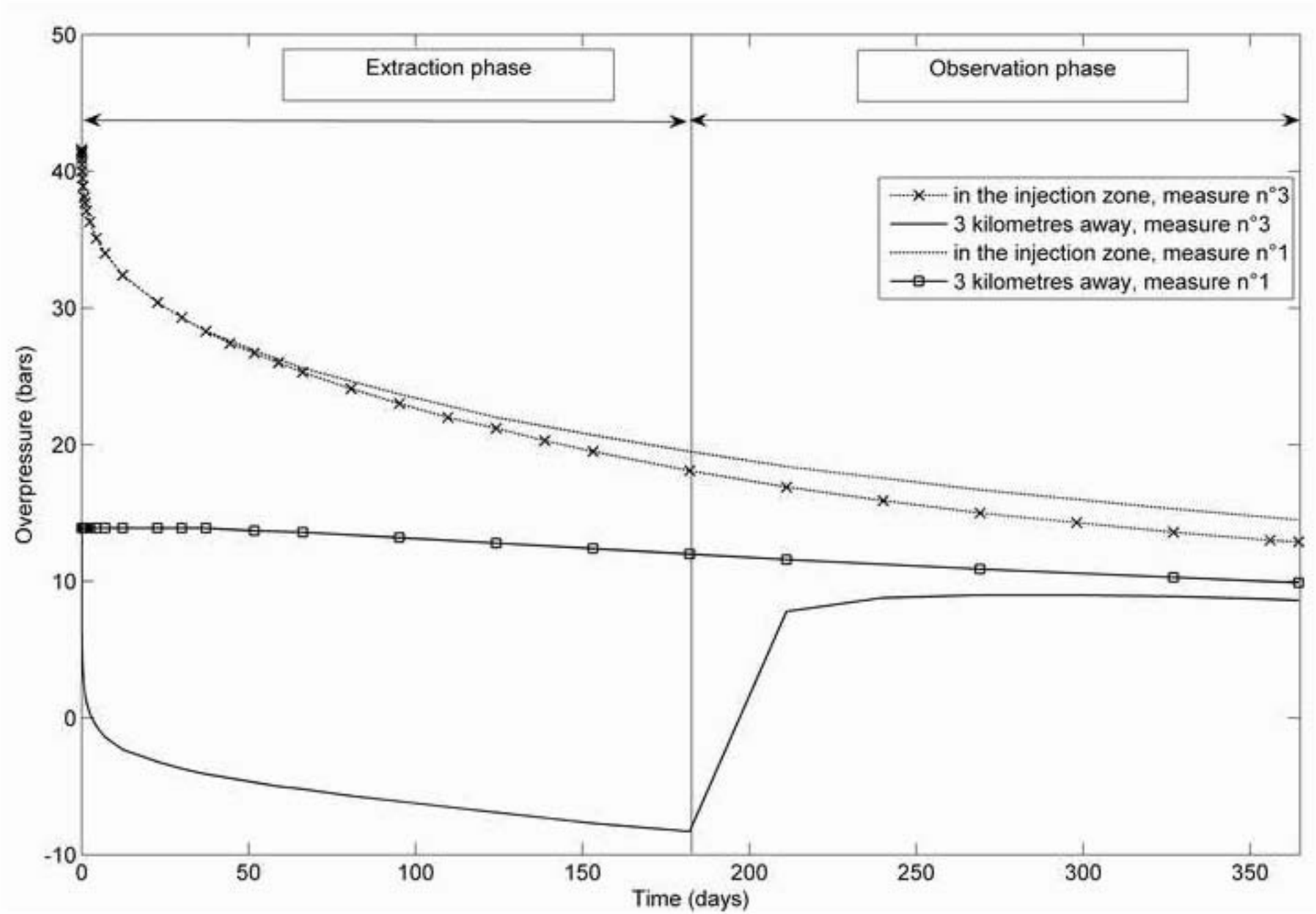

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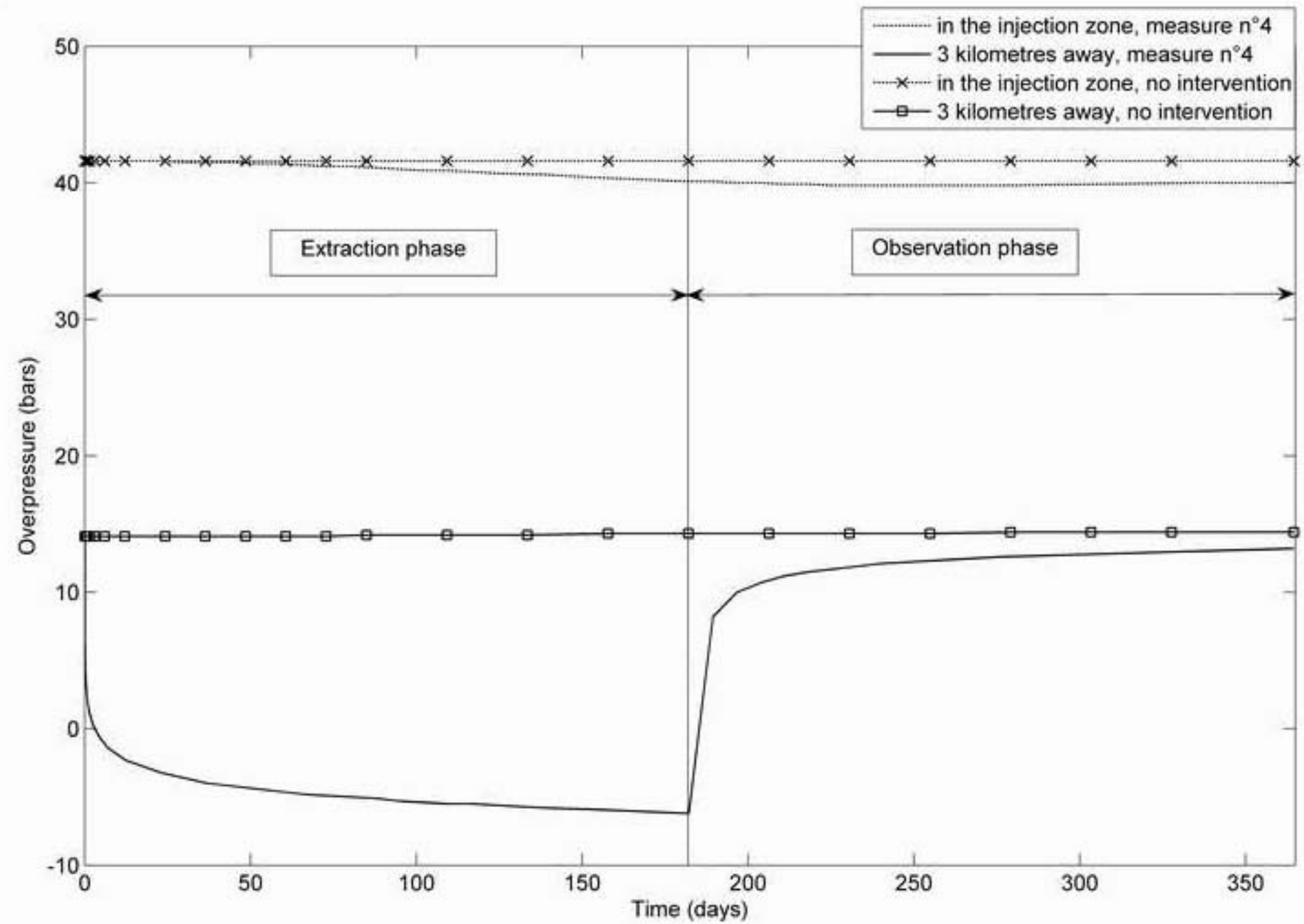

Figure 9
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