

# Deliverable 5.4

## Recommendations for safety and performance analyses of storage pilot in the Lusitanian Basin

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## Non-technical summary

This report assesses the safety and long-term performance of storing carbon dioxide (CO<sub>2</sub>) in a deep saline reservoir in Portugal's Lusitanian Basin. The work is part of the EU PilotSTRATEGY project and focuses on the Q4-TV1 prospect, located approximately 22 km offshore of Figueira da Foz in 85 m water depth. The pilot aims to inject up to 100 kts of CO<sub>2</sub> over 3 years to demonstrate storage at research scale. Under Portuguese Decree-Law 60/2012<sup>1</sup>, this injection volume is treated as a research pilot and is exempt from CO<sub>2</sub> storage licensing procedures, while still requiring robust safety assurance and monitoring. The objective is to demonstrate **no significant risk of leakage or harm to human health or the environment**, in line with the EU CO<sub>2</sub> Storage Directive and Decree-Law 60/2012.

The storage reservoir is a Lower Cretaceous sandstone aquifer at approximately **800–1200 m** below the seafloor. Containment relies on a **multi-barrier seal system**: i) a regionally continuous primary caprock of tight limestones/dolomites/marls more than 50 m thick, and; ii) a thick package of secondary seals (layers of mudstones/marls in overlying units) providing additional sealing capacity. The storage site is a gentle anticline with laterally continuous stratigraphy and **no major faults within the storage site**; mapped fault zones are about 9–11 km from the injection point. There is a single legacy well (Dourada-1C), plugged and abandoned in 1975, located 11.7 km from the planned injector. Together, these factors provide strong geological confinement and wide separation from potential leakage pathways.

A two-round risk assessment (screening + detailed modelling) concludes that the pilot has a **very low risk profile** due to the geology and planned engineering controls:

- **CO<sub>2</sub> remains contained:** Simulations indicate the CO<sub>2</sub> plume remains within the reservoir and does not reach mapped faults or the legacy well, even under conservative long-term scenarios (including 1000-year modelling).
- **Seal integrity is robust:** The caprock system remains intact under expected pressure conditions; any CO<sub>2</sub>-brine-rock interactions are localized and self-limiting, with no credible mechanism for creating a transmissive pathway through the seal system.
- **Seismic risk is low:** The site lies in a low-seismicity area. The pilot is operated with strict pressure control. Injection-induced seismicity is not expected to be felt; if any microseismicity occurs, it will remain well below natural seismicity levels and without felt effects onshore.

Overall, the pilot-scale operation is expected to be **safe and compliant**, with no plausible leakage pathway and negligible residual risks for the pilot phase. The same geological features that support pilot safety also support potential future commercial storage. The pilot is designed to **reduce uncertainty, derisk and improve models** (pressure response, plume behaviour, injectivity) before scaling-up to commercial scale, if that opportunity arises.

In the commercial phase scenario assessed, the final risk matrix identifies no hazards in the “High” or “Very High” zones of the risk matrix. However, it retains some hazards classified as **Significant** (in the sense of the CCS Directive risk management framework) for the commercial scenario. These are related to caprock uncertainty and integrity, as well as injectivity and storage capacity below expectations. These risks are considered manageable through pressure management, targeted additional site characterisation, and a risk-informed Monitoring, Measurement and Verification (MMV) and corrective measures framework and should be reduced and re-evaluated using pilot data before any commercial permitting decision.

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<sup>1</sup> Decree Law n.º 60/2012, de 14 de março, art. 2.º, n.º 3. Diário da República.  
<https://diariodarepublica.pt/dr/detalhe/decreto-lei/60-2012-553447>

## Executive Summary

A comprehensive risk and performance assessment for geological CO<sub>2</sub> storage at the Q4-TV1 pilot site in the offshore Lusitanian Basin, Portugal was carried out under Work Package 5 (WP5) of the PilotSTRATEGY project. The specific objective of WP5 is to ensure the proposed pilot injection meets the highest safety and performance standards, with no significant risk of leakage or harm to health or the environment, in full compliance with EU Directive 2009/31/EC<sup>2</sup> and Portuguese Decree-Law 60/2012<sup>3</sup>. To achieve this, the assessment was structured in two sequential rounds:

- **Round 1 (Preliminary Assessment):** A broad screening of all potential risks was conducted, including expert workshops to identify hazards and initial modelling to estimate their likelihood and impact. This round produced a comprehensive risk register and helped inform key decisions for the pilot design. It also served as a “decision gate” to flag which risks required deeper analysis in the second round.
- **Round 2 (Detailed Assessment):** A refined evaluation focused on the main risks identified in Round 1, incorporating much more detailed results from geological studies (WP2), reservoir and geomechanic simulations (WP3), and pilot implementation planning (WP4). This phase used advanced quantitative methods (e.g. stochastic dynamic models, probabilistic seismic hazard analysis PSHA, fault reactivation models, etc) to rigorously quantify risks and test worst-case scenarios.

Two operational scenarios were considered:

- a **pilot phase** involving injection of up to **100 kt** of CO<sub>2</sub> over 3 years (research-scale test), and;
- A **commercial phase** injecting 0.5–1.0 Mt of CO<sub>2</sub> per year over 30 years through the same injection well—totalling approximately 15–30 Mt. This phase could later expand to 4.7 Mt/yr by 2045 to include additional emitting sources, using extra injection wells and storage structures already identified in the northern sector of the Lusitanian Basin.

By comparing these, the study addresses both near-term pilot risks and the implications for a future scale-up. The methodology combined deterministic and probabilistic approaches – including Monte Carlo uncertainty analysis and stochastic numerical modelling. Overall, the WP5 assessment is designed to be transparent and aligning with regulatory guidance for CO<sub>2</sub> storage risk management and ensuring that all stakeholders can have confidence in the findings.

### Site Overview and Geological Context

The pilot site is located in the northern sector of Portugal’s Lusitanian Basin, approximately 22 km offshore from Figueira da Foz. The storage target is a **deep saline aquifer** within the Lower Cretaceous Torres Vedras Group, which consists of porous fluvial-deltaic sandstones at 820–1178 m depth below

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<sup>2</sup> European Parliament and Council of the European Union. (2009). Directive 2009/31/EC on the geological storage of carbon dioxide. Official Journal of the European Union, L 140, 114–135. <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32009L0031>

<sup>3</sup> Decree Law n.º 60/2012, de 14 de março, art. 2.º, n.º 3. Diário da República. <https://diariodarepublica.pt/dr/detalhe/decreto-lei/60-2012-553447>

the seabed. These sandstones have favourable reservoir properties – prior well data indicate high porosities (around 20%) and adequate permeability to store CO<sub>2</sub> at the planned injection rates.

The site benefits from a **multi-barrier seal system** that provides layered containment of the CO<sub>2</sub>. Immediately above the reservoir is the Cacém Formation caprock, a 50–100 m thick unit of tight limestone, dolomite, and marl that has very low permeability and serves as the primary seal. Additional overlying formations (the Aveiro and Espadarte Formations) comprising layers of marine mudstones and marls act as secondary seals, contributing for further vertical containment. Together, these seals constitute an effective barrier to upward migration of CO<sub>2</sub>. Indeed, seismic and well evidence show the stratigraphy is laterally continuous and undisturbed by major faults at the prospect area.

The storage structure itself is a broad, gentle anticline (four-way dip closure) that provides a structural trap for the injected CO<sub>2</sub>. No significant faults are present within the closure – the nearest mapped faults lie up to 9-11 km from the planned injection point. Additionally, there is only one existing well in the vicinity: Dourada-1C (Do-1C), an exploration well drilled in 1974 and plugged in 1975, located 11.7 km north of the proposed injection well. This legacy well's distance means it is highly unlikely that it is reached by the CO<sub>2</sub> injected during the pilot phase.

The region has **low natural seismicity**, especially in the northern basin where the site is located – monitoring recorded only a handful of small-magnitude events ( $M_L < 3$ ) offshore near the storage site over the past two decades. The current stress regime is extensional and not expected to drive fault movements.

The pilot injection will take place in a carefully chosen location within the structure that maximizes distance from any major geological discontinuities. Prior to injection, 3D seismic surveys must be acquired to define the baseline and refine the geologic model, ensuring that injection operations can be planned within safe limits.

### **Key Findings from the Risk Assessment**

The integrated risk assessment evaluated numerous potential leakage paths and other risks, and it concluded that the **Lusitanian Basin pilot can be operated with a very low risk profile**. The main conclusions for each phase are summarized below:

- **Pilot phase (<100 kt CO<sub>2</sub> injection):** assessed risk pathways are **Not significant** under pilot conditions.
  - The CO<sub>2</sub> plume is predicted to remain well confined in the reservoir and will not reach any bounding faults or the abandoned well Do-1C. The probability of leakage through the caprock is negligible – even under worst-case pressure build-up, the caprock maintains integrity (no fractures or transmissive pathways form).
  - Well integrity risks are Not significant: with only one new injector (and no observation wells) designed to modern standards, the chance of any well leak is extremely low (estimated <1% of injected mass in worst case).
  - Meaningful induced seismicity is also very unlikely; modelling indicates any injection-induced seismicity would be too low to be felt and well below natural seismicity levels.
  - Containment performance is adequate – multi-layer seals and modest injection volumes mean the CO<sub>2</sub> will stay trapped with a high degree of confidence.

All hazards (e.g. certain injectivity uncertainties) have straightforward mitigations. Importantly, **no scenario in the pilot analysis indicated any unacceptable or unmanageable risk** to containment, safety, or the environment. In short, the pilot injection is projected to be safe, with all major risks inherently low or well controlled.

- **Commercial phase**, injecting 15–30 Mt CO<sub>2</sub> in the same well: Even for a much larger injection over decades, the **overall risk remains low**, provided that the insights from the pilot and conservative design are applied.
  - The plume is expected to stay within the same structural compartment for a full commercial injection – modelling 1100 stochastic realizations over 1000 years showed the CO<sub>2</sub> did not reach the mapped faults or escape the reservoir in any scenario.
  - The likelihood of CO<sub>2</sub> migrating to the legacy well or causing any seal leakage over the long term was found to be extremely low (in the most extreme simulation, the plume came within 800 m of Do-1C with very low saturation, insufficient to cause leakage).
  - Caprock integrity remains robust for larger volumes; although a larger pressure footprint is generated, the caprock can tolerate it.
  - The risk of induced seismicity at scale is still assessed as minimal and manageable – by implementing a Traffic Light System (with real-time seismic monitoring and predefined response actions), the injection can be controlled to avoid any impacts from induced seismicity.
  - A few risks do scale with volume (for instance, injectivity or operational risks like well scaling or reservoir heterogeneity could introduce moderate uncertainties in a 30-year operation). However, none of these approaches a high-risk level, and all can be mitigated with engineering measures (e.g. periodic well stimulation, pressure management).

The Round 2 risk assessment explicitly updated the risk matrix for the commercial scenario using refined data and found that **no hazards fell in the “High” or “Very High” zones**; nevertheless, it retains **Significant** hazards that require continued risk-reducing measures and evidence from the pilot phase before scale-up. These are related to caprock uncertainty and integrity, as well as injectivity and storage capacity below expectations. Most leakage pathway risks (faults, abandoned well Do-1C, operational well leakage) remain **Not significant** in the updated.

The assessment leads to a set of recommendations structured in four main areas. **Future research and data acquisition** focus on reducing key uncertainties through additional seismic data and well-based characterisation of reservoir and caprock properties. **Injection design and operational strategies** emphasise conservative pressure management, phased development, and maintaining operational flexibility. **MMV and corrective measures** highlight the need for continuous pressure monitoring, plume tracking, geochemical surveillance, and microseismic monitoring to ensure early detection of deviations. Finally, **regulatory and legal considerations** stress the importance of aligning the pilot with permitting requirements and using its results to support future commercial-scale authorisation.

Overall, the risk assessment provides confidence that the offshore Lusitanian Basin site can be operated safely for CO<sub>2</sub> storage. Key initially flagged concerns – such as fault reactivation, caprock failure, well leakage, or induced seismicity – were thoroughly analysed and classified as low/very low risk after the detailed Round 2 evaluations. The few operational uncertainties remaining (e.g. caprock uncertainty and integrity, with injectivity and storage capacity below expectations), are *Significant* but manageable and are accompanied by mitigation strategies.

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## 1. Introduction

This report presents the risk and performance assessment for a CO<sub>2</sub> injection pilot in the Lusitanian Basin, Portugal, in the scope of the EU funded PilotSTRATEGY project. The selected storage site is located offshore, in the northern sector of the Lusitanian Basin, at 22 km from Figueira da Foz (Figure 1), where a deep saline aquifer has been identified as the prospective site for pilot-scale CO<sub>2</sub> injection. The selection of the offshore site followed a workflow involving geological characterization, reservoir modelling and social acceptance studies, and the offshore site proved the most suitable due to:

- i. **Good data quality and coverage**, provided by 2D and 3D seismic surveys and several offshore oil exploration wells;
- ii. **Excellent reservoir quality** in a deep saline aquifer in the Lower Cretaceous sandstones;
- iii. **Low active** seismicity;
- iv. **Containment conditions** provided by a multi-layered system (Lower Cretaceous reservoir sealed by Upper Cretaceous carbonated rocks and clays)
- v. **Expected minimal impacts** for storage and higher social acceptance given the offshore setting;
- vi. **High storage capacity**, enough to ensure storage of at least 90 Mt CO<sub>2</sub>;
- vii. possibility to upscale from **Pilot phase** to **Commercial phase** due to the existence of other suitable storage prospects in the vicinity.

Work Package 5 (WP5) of PilotSTRATEGY evaluates the integrity, stability, and long-term performance of the pilot injection site. It combines information from geological characterisation (WP2), numerical modelling (WP3) and stakeholder engagement (WP6) to derive qualitative and quantitative risk assessment to contribute to the Pilot Development Plan and Monitoring, Measurement and Verification (MMV) plan (WP4).

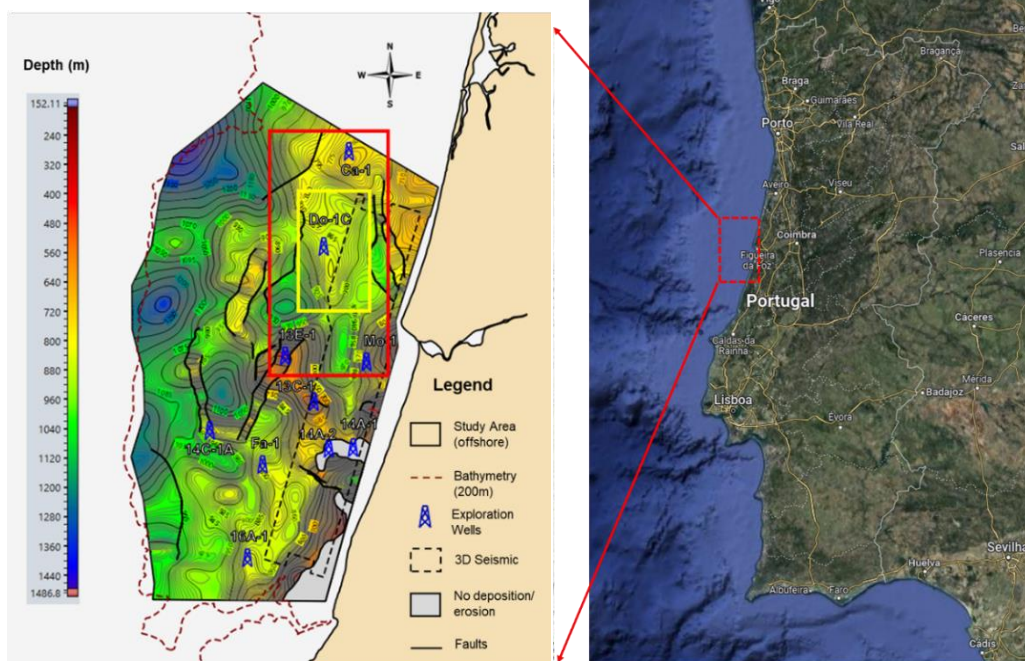


Figure 1: Location of the study area in the Lusitanian basin, showing the depth structure map of the top of the reservoir, highlighting the boundary of the static geologic model by the red rectangle, and the boundary of the reservoir model in yellow.

## 1.1 Objectives and scope of the deliverable

This deliverable provides a structured evaluation of risks for the **Pilot** and future **Commercial** CO<sub>2</sub> injection phases. It ensures that the storage site meets the highest safety and performance standards, guaranteeing no significant risk of leakage or harm to human health or the environment, in full compliance with the EU CCS Directive (2009/31/EC) and the Portuguese Decree-Law (DL) 60/2012<sup>4</sup>.

The risk assessment focuses on the storage component, with the capture and transport risks not addressed, and follows a procedure detailed in deliverable D5.1 (Le Guenan et al. 2022), which includes two rounds of assessment:

- **Round 1** – involves developing a comprehensive risk register and conducting preliminary risk assessments, incorporating expert input from all relevant Work Packages (WPs). It also includes a decision analysis to identify the risks that will undergo detailed evaluation in Round 2;
- **Round 2** – A detailed evaluation of main risks selected in Round 1 and incorporating detailed results from site characterization (WP2), reservoir and geomechanical modelling (WP3), and pilot implementation planning (WP4).

This deliverable provides essential feedback to the design of the pilot injection site and the MMV plan and establishes the foundation for future updates of the risk register if a pilot injection site continues to improve the understanding of the storage complex performance.

## 1.2 Regulatory framework

The regulatory framework governing geological storage of CO<sub>2</sub> in Portugal is defined by Decree-Law 60/2012 which translates the EU Directive 2009/31/EC on CO<sub>2</sub> Geological Storage (CCS Directive). DL 60/2012 establishes the legal basis for ensuring that CO<sub>2</sub> storage is carried out completely safe and permanent and without unacceptable risks to human health or the environment in the Portuguese territory. It outlines the requirements for:

- site characterization;
- risk assessment;
- storage permitting;
- monitoring, reporting, corrective measures; and
- long-term liability transfer to the competent authority.

Article 2, paragraph 3, of DL 60/2012 exempts projects injecting less than 100 kt for research purposes from the licencing procedures for CO<sub>2</sub> storage<sup>5</sup>. This is the case of the pilot phase proposed by PilotSTRATEGY. For CO<sub>2</sub> storage projects exceeding 100 kt, DL 60/2012 applies. According to the Decree Law, the Ministry responsible for geological resources grants **storage concession contracts**, while the Directorate General for Energy and Geology (DGEG) issues **exploration licenses** for drilling and injection tests that assess the suitability of a potential storage reservoir. Holders of exploration licenses receive preference for concession attribution.

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<sup>4</sup> Decree-Law n.º 60/2012, de 14 de março, art. 2.º, n.º 3. Diário da República.  
<https://diariodarepublica.pt/dr/detalhe/decreto-lei/60-2012-553447>

<sup>5</sup> However, DL 60/2012 includes a safeguard that this does necessarily exempt research projects from other applicable regulations (namely, water resources regimes in maritime space).

Risk assessment, required under Annex I of DL 60/2012, must cover **hazard characterization, exposure assessment, effects assessment, and overall risk characterization**. This involves identifying potential leakage pathways, estimating leakage magnitude, evaluating pressures, injection rates, and secondary effects, and assessing impacts on human health and the environment. The final risk evaluation must integrate uncertainties and determine the short and long-term safety and integrity of the storage complex, including worst case leakage scenarios.

Offshore CCUS activities must also consider the regulatory framework of activities in the maritime area, namely the PSOEM (the Portuguese Maritime Spatial Plan). According to the DL 38/2015 and the Resolution of the Council of Minister 203-A/2019, which establishes the policy for the planning and management of the national maritime space in accordance with the European Directive no. 2014/89/UE, the pilot phase does require the acquisition of a “Title for the private use of the maritime space” (TUPEM) that shall be awarded by the Directorate-General for Natural Resources, Safety and Maritime Services (DGRM, Article 51<sup>o</sup>).

DL 38/2015 states that the awarding of a TUPEM for new activities depends on the previous approval of an allocation plan (Article 50(1)). Nevertheless, for **scientific research activities, the TUPEM may be exempted from previous approval of an allocation plan** by decision of the members of the Government responsible for the sea affairs and environment (Article 50(2)).

To support the consistent implementation of the Directive 2009/31/EC across Member States, the European Commission has issued a series of Guidance Documents, GD1-GD4, firstly issued in 2011 and revised in 2024 (EC 2024). The 2024 revised **Guidance Document 1 (GD1) - CO<sub>2</sub> Storage Life Cycle and Risk Management Framework** – describes the overall approach to risk management for CO<sub>2</sub> storage sites, including how to demonstrate no significant risk of leakage or harm. This risk assessment follows the requirements set out in the DL 60/2012, the CCS Directive and its Guidance Document 1, ensuring that the results presented here are consistent with Portuguese and European standards for safe geological CO<sub>2</sub> storage.

### 1.3 Report structure

This deliverable is organised as follows. **Chapter 2** provides an overview of the regional context, summarising the geological setting, site characterisation, and the key outputs from WP3 and WP4 that support the WP5 analyses. **Chapter 3** presents the preliminary risk identification, synthesising the results of Round 1 and introducing the WP4 pilot-related decisions that initiate Round 2. **Chapter 4** delivers the synthesis of the risk analysis in Round 2, including the integrated assessment of the main risks identified in Round 1, the updated risk matrix, and the interpretation of the Round 2 findings. **Chapters 5 and 6** present the recommendations and conclusions, respectively, providing guidance on future research needs, monitoring strategies and design considerations from the WP5 perspective.

While the main body of the report is intentionally concise, supporting material is provided in the **Appendices**. Some of the risks discussed in Chapter 4 were quantified in WP3 using numerical modelling; although their evaluation is summarised here, readers seeking additional technical detail are referred to Deliverable D3.5 – Report on near wellbore, caprock and faults/fractures integrity (Perreira et al., 2026b).

## 2. Overview of regional context

### 2.1 Site location and geological setting

The storage site is located in a subsurface geological structure, designated as Q4-TV1 prospect in the Northern sector of the Lusitanian Basin at approximately 22 km offshore from Figueira da Foz (Figure 2). The Lusitanian Basin is a Meso-Cenozoic basin, that evolved as a rift basin throughout most part of the Mesozoic. The evolution of this basin occurred during the Late Triassic – Early Jurassic with the onset of the first rifting event. Two other rifting events occurred during the Late Jurassic and Early Cretaceous. Continental break-up occurred close to the transition between Early and Late Cretaceous. During that evolution, Mesozoic sedimentation alternated between deposits with continental influence and marine deposits.

The basin comprises a stacked succession of Triassic to Cenozoic sedimentary formations shaped by multiple rifting events, salt tectonics and later compressional phases, all of which controlled depositional environments and the present-day distribution of reservoir and seal units. The lithostratigraphic chart and a representative seismic section illustrate the key stratigraphic horizons mapped regionally, including the Top *Espadarte*, Top *Aveiro Group*, Top *Cacém Formation*, Top *Torres Vedras Group* and Top *Alcobaça Formation* (Figure 3). This seismic section demonstrates the continuity of these units across the offshore area and highlights the stratigraphic sequence that composes the storage complex (Figure 3).

The identification and selection of the pilot site resulted from the subsurface geo-characterization studies conducted within the scope of the PilotSTRATEGY project and detailed in D2.7 (Marques da Silva et al., 2023). In these studies, petroleum legacy well data and 2D/3D seismic surveys were utilised for the petrophysical and geophysical interpretation of the storage complex in the offshore setting of the basin and to define the reservoir and caprock conceptual and static geological models of this area.

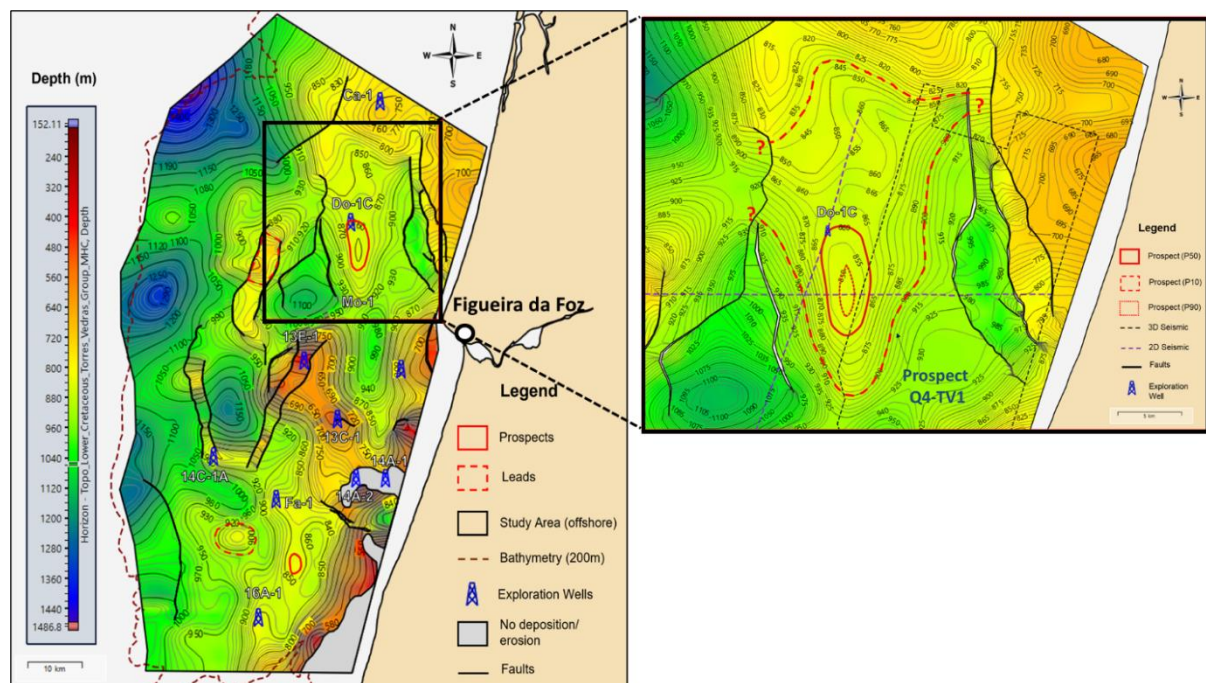


Figure 2: Location of the pilot storage site showing the faults and the position of the Do-1C legacy well within the prospect Q4-TV1. P10, P50 and P90 contours of the prospect are also shown.

The ties between the seismic data and the several key exploration wells (Ca-1, Do-1C, Mo-1 and 13E-1) show a gently folded geometry in which the reservoir, caprock, and underburden units are laterally continuous and structurally undisturbed. The targeted CO<sub>2</sub> reservoir interval lies within the Lower Cretaceous siliciclastic succession, overlain by a thick, regionally persistent caprock composed of low-permeability carbonates and marls. Above this, the overburden comprises more heterogeneous but laterally extensive Upper Cretaceous (Aveiro Group) and post-Cretaceous sediments that provide additional sealing capacity.

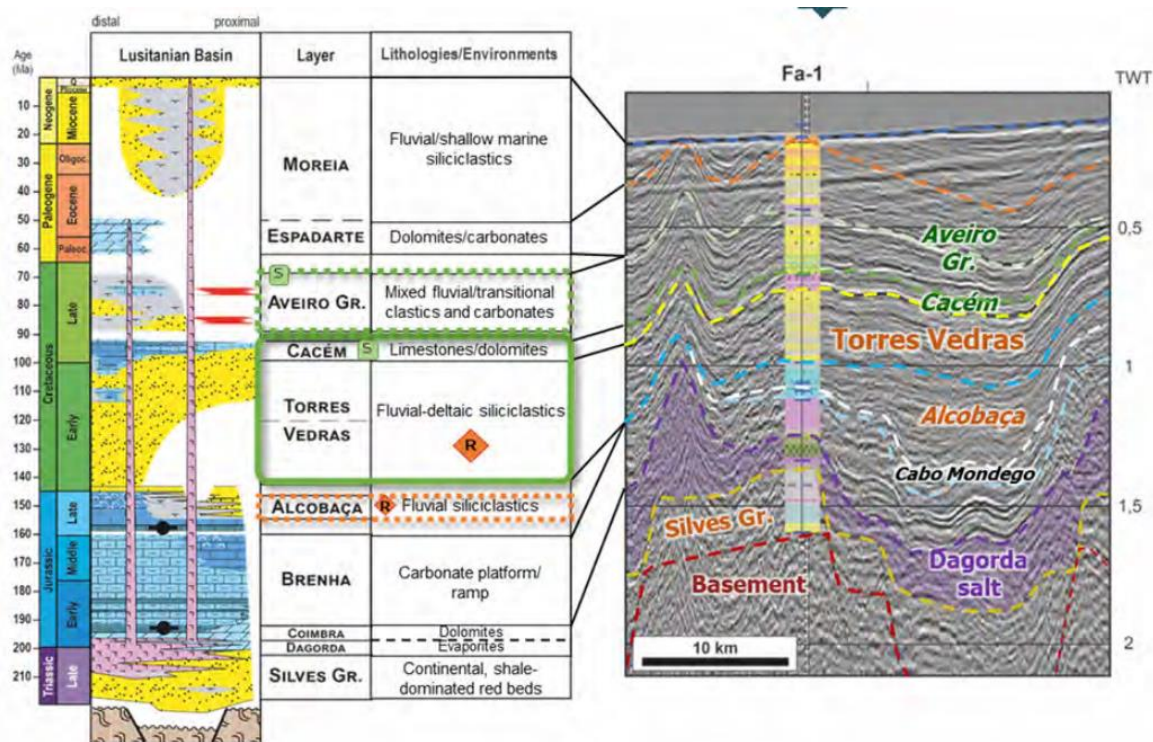


Figure 3: Lithostratigraphic chart of the Lusitanian Basin showing its main tectono-stratigraphic units alongside a seismic section illustrating the mapped key horizons.

This prospect lies in the northern flank of the broad anticlinal structure that was penetrated by an exploration well Dourada-1C (Do-1C), and the trap type consists in a four-way dip closure with about 25 km<sup>2</sup>, in the P50 scenario, and 250 km<sup>2</sup> in the P10 scenario (albeit in this case it is defined by a semi-closed structure, partially bounded to the east and west by N-S oriented faults). The next subsections will detail reservoir and caprock properties.

## 2.2 Storage reservoir properties

The selected deep saline aquifer is composed by siliciclastic deposits of Early Cretaceous Torres Vedras Group (locally designated as Figueira da Foz Formation<sup>6</sup>). It consists of fluvial–deltaic sandstones interlayered with claystones, forming a laterally extensive and regionally continuous system. Depth-

<sup>6</sup> The complex tectonic evolution of the Lusitanian Basin led to the differentiation of many sub-basins in which the Cretaceous formations, although maintaining the overall sedimentological features, do present differences and, accordingly, local specific designations have been adopted for lateral equivalent formations. In this report, as in all others PilotSTRATEGY, we will adopt primarily the designations from Petroleum Systems in Portugal, as adopted by DGEG (see DGEG website for [Petroleum Systems](#)), since most of the data used in the project results from the hydrocarbon exploration efforts conducted in the Lusitanian basin.

converted seismic data indicate that the top of the reservoir ranges from about 865 m to 1205 m at the storage prospect, although at regional scale there are significant depth variations due to salt-driven tectonics and differential subsidence. Reservoir gross-thickness estimates in the target area is about 350 m, with maximum values (>450 m) in basinward sectors where uninterrupted sedimentation occurred.

Petrophysical analyses from available vertical wells indicate reservoir net-to-gross ratios between 11–82% and average porosities of 19–23%, with permeability primarily governed by diagenesis and facies transitions. According to WP3 estimates (D3.2, Pereira et al., 2024) permeability ranges widely from well to well, e.g., median values between 39–244mD estimated from the well Do-1C. Interbedded claystone layers create internal barriers to vertical migration of the CO<sub>2</sub>, but do not significantly disrupt lateral continuity of the main reservoir bodies. Formation water salinity, as interpreted from geophysical logs, ranges from 10 g/L to 130 g/L. This large variation of salinity values mainly depends on the depth of the target reservoir identified from shallower and deeper wells in the basin, with an average value of about 56 g/L (the reference value used in the modelling tasks).

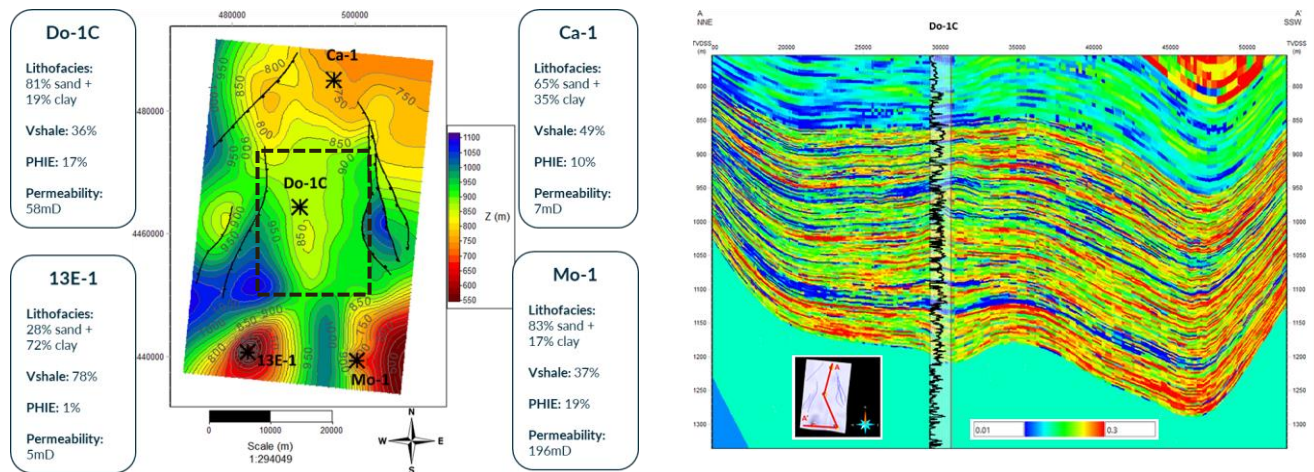


Figure 4: Left: Top depth map of the reservoir, showing the location of the nearest oil exploration wells (Ca-1, Do-1C, 13E-1 and Mo-1) and the average petrophysical parameters obtained from geophysical log interpretation. The dashed rectangle represents the location of the pilot site (Figure 2). Right: One realization of the stochastic simulation of effective porosity shown in a cross-section of the static model, for the reservoir (colour scale represents porosity).

The optimization of the well location and admissible injection rate is described in D3.3, taking into account the uncertainties from the static and dynamic models. It used as objective function the bottomhole injection pressure to minimise risk of fracturing the reservoir and caprock, and considered the risk imposed by the legacy oil exploration well (Do-1C) and the fault systems located to the east and west of the pilot site. Location of the well is given by coordinates 40°13'32"N, 9°04'09"W (WGS84 datum), with an injection rate varying between 0.5 Mt/yr and 1.0 Mt/yr. The well is open at two injection intervals, from 1025 –1065 m and from 1155 –1205 m below the mean sea level.



*Figure 5: Onshore analogue of the Lower Cretaceous reservoir.*

## 2.3 Caprock description

The caprock of the storage complex is the Cacém Formation (which is the lateral equivalent locally known as the Costa D'Arnes Formation), a regionally continuous unit composed of limestones, dolomites, and marls. Seismic and well data show that the Cacém Formation exhibits low-to-moderate porosity but very low permeability (particularly in the bottom zone in the interface with the reservoir), and forms a strong, laterally persistent (regional) seismic reflector. It is typically composed of two sub-units, in which the Lower Cacém Formation consists of a thin shale/marl package (<50m), followed by the Upper Cacém Formation, with 50 m to 100 m of limestone and/or dolomite.

Do-1C and 13E-1 wells (see location in Figure 4) show the best seal facies of the whole seven wells in the offshore region, with the presence of unweathered limestones/dolomites and shales. This may be locally explained due to the combination of lack of syn-diapirism deposition (with rapid deposition with no subaerial exposure), and no fracturing and/or folding during the tectonic inversion phases. Do-1C well, located in the Q4-TV1 structure, encountered ~52 m of Cacém Formation caprock composed of an upper limestone/dolomite unit and a lower marl-rich unit (Figure 6), confirming very low permeability. Moreover, the caprock is calcite-rich, which influences chemical stability.

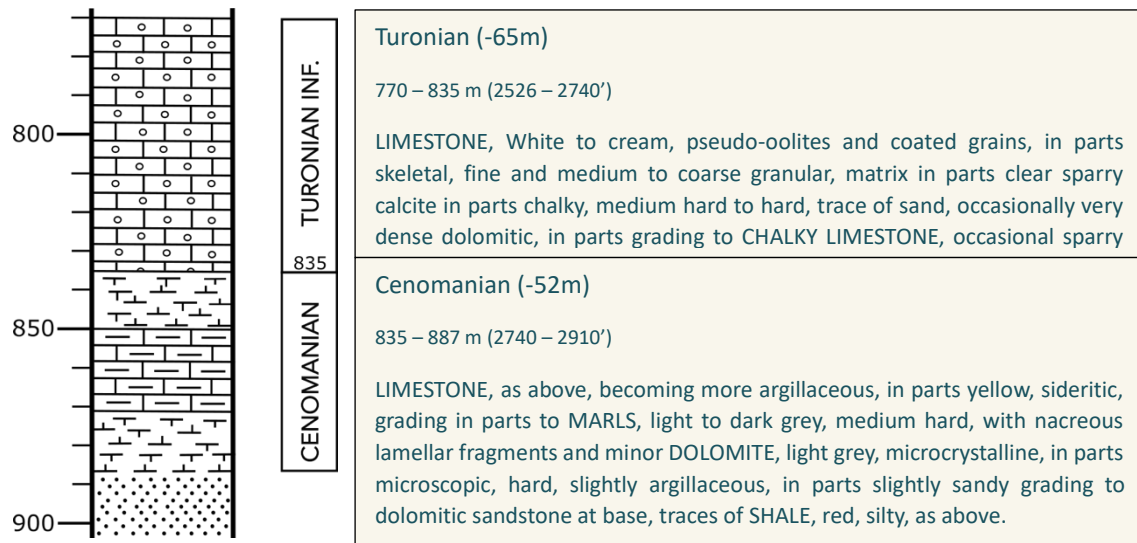


Figure 6: Lithostratigraphic sequence of the Upper Cretaceous overlaying the reservoir from the Do-1C oil exploration well report.

Onshore, where it has been crossed by groundwater boreholes, the transition of the Cacém formation to the underlying reservoir unit is through a sequence of increasing marly and clayey components (Figure 7) and known to be thicker offshore and to compose the first seal of the reservoir (see D2.11).



Above the primary seal, the Aveiro Group and the Espadarte Formation act as potential secondary sealing units. These formations comprise fine-grained marine mudstones and marls and contribute additional vertical containment capacity. Together with the Cacém Formation, these secondary seals form a robust overburden package with a combined thickness of roughly 650 m. The secondary seal is mainly presenting higher values (>50%) of volume of clay and lower values (<10%) of effective porosity at the locations close to the wells Ca-1, Mo-1, and 13E-1, while lower values (<50%) of volume of clay and higher values (>10%) of effective porosity were simulated close to the location of the well Do-1C.

Figure 7: Onshore analogue of the Upper Cretaceous formations at Nazaré, with the clay, marls and dolomites at the base of the sequence, grading into the limestones at the top.

## 2.4 Fault zones and legacy wells

The 2D and 3D seismic surveys were interpreted for fault identification across the offshore study area, extending from Nazaré to Figueira da Foz (Figure 2). Fault strikes are predominantly clustered along N–S and NW–SE orientations, with only a limited number of structures striking W–E. The majority are normal faults, although some reverse faults associated with salt halokinesis are also present. Fault throws commonly reach several hundred metres, while throws of a few tens to a few hundred metres are also frequent. This fault framework controls the development of the regional structural architecture of the basin, including the formation of structural highs, grabens, and half-grabens.

Within the Q4-TV1 prospect itself, no major faults are discernible in the available 2D and 3D seismic data. However, at the broader regional scale (approximately 250 km<sup>2</sup>) surrounding the storage site, six faults have been mapped (Figure 2). These faults define two main fault zones. One fault zone is located approximately 8.9 km east of the proposed injection site and is predominantly oriented N–S. The second fault zone comprises three faults located further west, with the closest at approximately 11 km from the prospect and displays a dominant NW–SE orientation. This latter fault system coincides with structures mapped in the 1:500,000 geological map and in the neotectonic map of Cabral and Ribeiro (1988), and are responsible for the exposure of Cretaceous formations at the seabed several kilometres east from the proposed injection site, disrupting the physical continuity between the onshore and offshore Early Cretaceous, and avoiding the existence of risks on the onshore aquifers.

At present, no direct information is available regarding the sealing properties of these faults (e.g. permeability or transmissivity). Consequently, they must be treated as a potential risk factor, possible leakage pathways, particularly for commercial-scale development, and warrant additional data acquisition and targeted investigation in subsequent project phases.

Only one legacy well is located in the storage structure: the Dourada 1C (Do-1C) exploration well, roughly 11.7 km north from the proposed CO<sub>2</sub> injection well (Figure 2). Drilling for Do-1C was carried out between in 1974/75 and it reached a total depth of 3667 m. The well was drilled for hydrocarbon exploration and plugged and abandoned after completion in 1975. Given the time since abandonment and the lack of data about its status, Do-1C must be considered as a potential leakage pathway if its integrity is compromised and the CO<sub>2</sub> plume reaches it.

## 2.5 Natural Seismicity

Natural seismicity was one of the criteria applied during the technical evaluation to decide between onshore and offshore sites. As such, the selected injection site is located in a region of lowest seismicity zone in the country.

The seismicity of the region was characterised in D2.3 (Wilkinson et al. 2024). Epicentres of magnitude  $M_L > 3$  are primarily concentrated in the southern part of the Basin, possibly related to a major tectonic feature in the region, the Nazaré fault (NF) and its associated fault system (Figure 8). Further north in the Lusitanian basin, seismicity  $M_L > 3$  range is **practically non-existent** and in the offshore is dispersed, and apparently not related to the oceanic extension or any mapped fault.

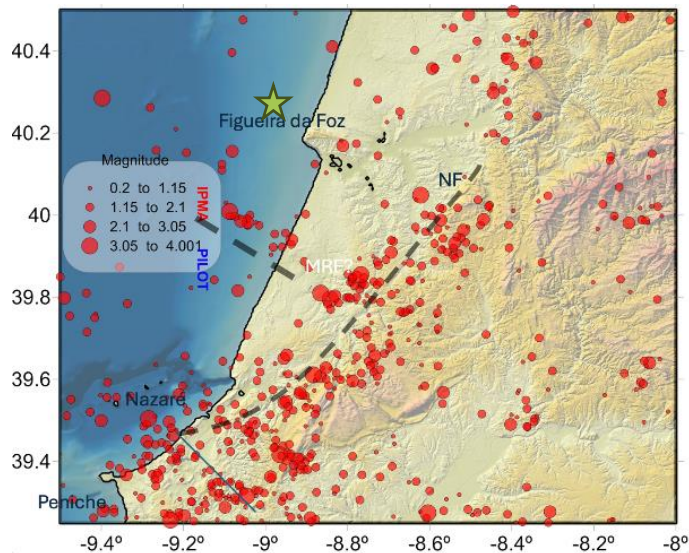


Figure 8: Seismicity for the period between 2000 and 2022 for all magnitude. (MRF - Possible Monte Real Fault (not mapped) and Nazaré Fault (NF). Green star indicates the location of the storage site.

According to the Eurocode 8 (EC8), the EU standard for the design and construction of earthquake-resistant structures, the storage site is located in zone 1.5 for a seismic action type I (seismic event in a far-field scenario), with a maximum acceleration of  $0.6 \text{ m/s}^2$ , and in zone 2.4 for a seismic action type II (seismic event in a near-field scenario) with a maximum acceleration of  $1.1 \text{ m/s}^2$  (Figure 9).

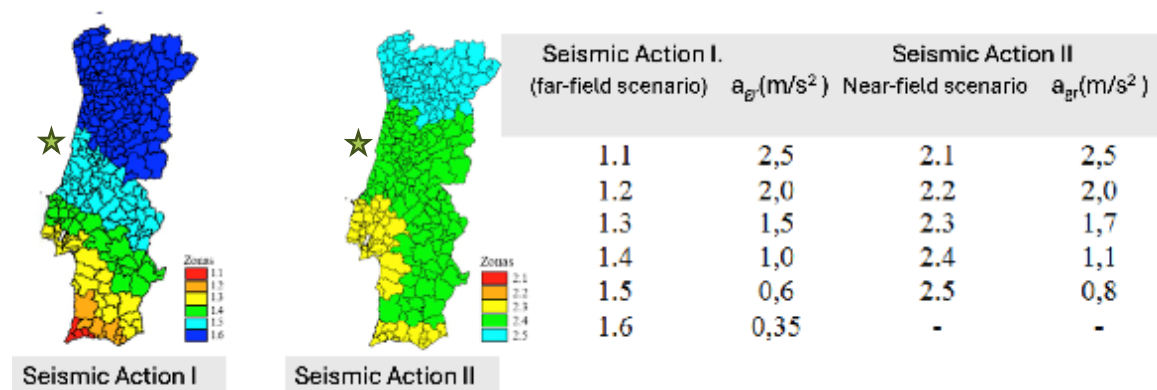


Figure 9: Seismic zoning in Mainland Portugal considered in Eurocode 8 (NP EN 1998-1) and the National Annex (2009). Source: <https://spessismica.pt/eurocodigo-8/>. Green star indicates the location of the storage site.

### 3. Preliminary risk assessment and pilot implementation plan

In the context of the CCS Directive, risk management should demonstrate that geological storage of CO<sub>2</sub> within a designated storage complex can be or is done safely in accordance with Article 1 and Article 4. Risk assessments should be documented in a transparent and traceable manner to build trust among competent authorities and stakeholders that the process has been comprehensive and that the results are both scientifically robust and operationally relevant.

A key principle of risk management in the Guidance Document GD1 (European Commission, 2024) is that the level of risk is reduced **As Low As Reasonably Practicable** (ALARP). This implies that some risks may be assessed as contingent acceptable or tolerable if the cost or effort associated with reducing the risk is disproportionate to the level of risk, and the risk can be maintained at a not significant level. GD1 advises classifying risks according to their **significance**:

- **Not significant risks**<sup>7</sup>: risks that do not call into question the purpose of the CCS Directive for the storage site concerned; and
- **Significant risks**<sup>8</sup>: risks that must be reduced to *Not significant* by taking risk-reducing measures in order to meet Article 4(4)<sup>9</sup> and subsequently achieve compliance with the conditions for transfer of responsibility.

As set out in the PilotSTRATEGY Grant Agreement, this risk assessment focus only in the storage site and operations, with risk related to capture and transport of CO<sub>2</sub> lying outside of the scope. This risk classification must ensure that, at a high level, storage sites will satisfy three main requirements:

- integrity**: confidence that the site is secure with no significant risk of leakage or material adverse impacts from induced seismicity, ground motion or earth deformation.
- injectivity**: the site has suitable reservoir properties that allow for sustained injection at required rates without having a negative impact on the integrity of the storage site.
- capacity**: sufficient storage volume is available or can be engineered to be available.

Two primary scenarios, aligned with WP4 objectives, were studied:

- Pilot phase**: aiming to inject a maximum of 100 kt CO<sub>2</sub> during a period of three years. This mass injection limit qualifies this phase as research focused, lying outside from the licensing and permitting procedures under DL 60/2012.
- Commercial phase**: Defined by the maximum estimated injection rate of **0.5 Mt/yr to 1.0 Mt/yr CO<sub>2</sub> for a period of 30 years in the same injection well** and the same Q4-TV1 geological structure. This phase could later expand to include additional emitting sources, using

<sup>7</sup> Although the definition is maintained as in the original guidance document, the designation **Not significant** is here preferred to the designation **Insignificant** used in GD1.

<sup>8</sup> The CCS Directive defines 'significant risk' as "a combination of a probability of occurrence of damage and a magnitude of damage that cannot be disregarded without calling into question the purpose of this Directive for the storage site concerned";

<sup>9</sup> "A geological formation shall only be selected as a storage site, if under the proposed conditions of use there is no significant risk of leakage, and if no significant environmental or health risks exist."

additional injection wells and storage structures already identified in the northern sector of the Lusitanian Basin<sup>10</sup>. The commercial phase would be fully compliant with DL 60/2012.

The purpose of the pilot phase is to **derisk** the commercial phase, by acquiring data about the geological storage complex on which the uncertainty is higher. Thus, the risk acceptance is inherently different for the two phases. Risk evaluation during the pilot phase is built on the current understanding of the geological and environmental conditions, and there is more tolerance to risk than for the commercial phase, since the CO<sub>2</sub> volumes involved are small and operations will run for a short period. For the commercial phase assessment, it is assumed that the pilot phase will have reduced uncertainties, providing the information needed to make informed decisions and manage risks in the commercial phase.

### 3.1 Methodology

The methodology for risk scenarios identification and assessment is outlined in D5.1 (Le Guenan et al., 2022) and depicted in Figure 10. It follows a two round-round approach. First, a light version of the process (**Round 1**) is carried out to promptly screen all possible risk events and identify which ones require deeper investigation. In a second round (**Round 2**), more detailed modelling and analysis are focused on the events flagged as relevant in the first round.

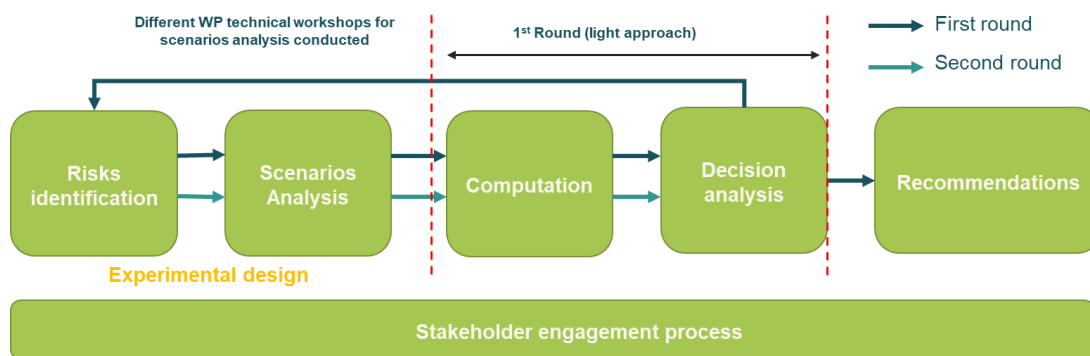


Figure 10: Outline of the approach to risk assessment and safety performance in PilotSTRATEGY.

The first step is **comprehensive risk identification** covering all events that could affect storage safety or performance, including their causes, consequences and interactions. This uses **generic risk lists** adapted to the site and **bow-tie diagrams**. Based on this inventory, an experimental design is prepared for each scenario, validated in workshops with WP2/3/4 and revised after the first analysis round.

In the **computation phase**, probabilities and impacts of key events are quantified following the experimental design. The analysis conducted in the scope of WP5 uses data and models from WP2 and WP3 or simplified stochastic models to simulate well behaviour, induced seismicity, CO<sub>2</sub> plume evolution, etc. Round 1 relies on simple models for rapid outputs; when modelling is not possible, expert opinion is used. Round 2 uses more detailed models for critical risks where further investigation is needed.

<sup>10</sup> The STRATEGY CCUS project indicated 4.7 Mt/yr as the total amount being transported by 2045. These values are being revised in the CTS project. Source: Coussy, et al. 2022. *Deliverable D5.3: Economic Evaluation of CCUS Scenarios in Eight Southern and Eastern European Regions*. Strategy CCUS Project.

Whenever the Round 1 assessment identified a relevant risk, that risk was flagged to Round 2 for detailed analysis. If a given risk is labelled as **Not significant** at Round 1, the analysis stops there. Hence, Round 1 computation is intrinsically conservative, working on worst-case scenarios, to ensure that no significant risk is incorrectly identified as Not significant.

**Decision analysis** integrates the modelling results and evaluates design options. Round 2 updates the decision analysis with improved simulations, forming the basis for final recommendations. **Stakeholder engagement** runs throughout the process to help capture risk perceptions, integrating additional concerns and adjust the assessment approach. The **final recommendations** draw on results from both rounds and address future research needs, design and option choices, draft monitoring and corrective measures plans.

### 3.2 Initial risk identification

The first step of the initial risk identification consisted in the registration of the risks. The risk registration consisted in identifying and listing all the possible events that can be subject to risk analysis. This selection was site specific using as guidelines the lists of Features, Events and Processes (FEP) (Savage et al., 2014) and CO2QUALSTORE (DNV, 2010) procedure for risk identification, as well as other public domain offshore CCS projects.

A Generic Risk Registration was accomplished in a **HAZID (hazard identification)** workshop with the Portuguese consortium team members (University of Évora, ICS and Galp). Building on the 137 FEPs, a total of forty-six risks have been identified (Table 1) and organised in seven risk categories and three risk types (Performance, Safety and Stakeholder Management). The risks have been organized by category to facilitate selecting the most important scenarios for analysis (Figure 11). This list of generic risks is added to this report as Appendix I and kept as a live XLS document for updating under the Risk Management Strategy during the pilot phase implementation.

*Table 1: Generic list of risks to the offshore pilot in the Lusitanian basin.*

Risk Category	Main event	Type of risk
Containment	CO <sub>2</sub> accumulation in a secondary reservoir following unexpected vertical migration.	Safety
	Slow rate of CO <sub>2</sub> trapping in the reservoir	Performance
	Leakage through operational well	Safety
	Leakage through an abandoned well	Safety
	Leakage through caprock due to pressure build up	Safety
	Leakage through caprock due to poor geologic characteristics	Safety
	Leakage through faults	Safety
	Chemical interaction of injected CO <sub>2</sub> with caprock	Safety
	Insufficient and ineffective monitoring during storage	Safety
	Leakage through observation well	Safety
	Expected lateral extent exceeded (CO <sub>2</sub> ): Non-expected leakage paths (spill)	Safety
	Migration of formation brine outside expected boundaries. Increased displacement of high salinity formation: Interaction with other resources	Safety
	Reservoir pressurization due to unexpected compartmentalisation	Safety
Economic	Pilot costs higher than estimated	Performance
Injectivity	Reduced injection capacity / reduced well efficiency	Performance
	Precipitation effect around the wellbore	Performance
	Flow modifications: groundwater flow modifications, within the reservoir or in other layers of the storage complex.	Performance
	Injectivity loss	Performance
	injectivity below expectations	Performance

Risk Category	Main event	Type of risk
Legal & Governance	Disruption by a later activity.	Performance
	Potential public resistance to the project	Stakeholder Management
	Lack of political will to implement CCS project	Stakeholder Management
Operational	CO <sub>2</sub> -seal/fault rock interaction	Safety
	Expected lateral extent exceeded (CO <sub>2</sub> ): Interaction with other resources	Performance
	Unexpected seabed risks	Safety
	Damage of the well head	Safety
	Failure in ensuring CO <sub>2</sub> in supercritical phase in the sink	Performance
	Simultaneous operations in injection site (even though with different objectives)	Performance
	Drilling window and rig unavailability	Performance
	Disruption of other uses (injection of effluents, oil production, geothermal energy,	Performance
	Hazards resulting from induced seismicity	Safety
	Leakage as a result of non-natural seismicity	Safety
	Infrastructures damage related to natural seismicity	Safety
	CO <sub>2</sub> interaction with well cement and materials	Safety
	Accidental Over-filling	Safety
	Impossibility of Surface CO <sub>2</sub> storage	Performance
NOx deposition in nature areas	Safety	
Social	Restrictions to fishing activities around the well	Stakeholder Management
	Impact on touristic activities	Stakeholder Management
	Loss of employment in other sectors	Stakeholder Management
Storage capacity	Permeability degradation during injection due to chemical/mineral precipitation	Performance
	Undetected flow barriers in the reservoir	Performance
	Low average permeability	Performance
	Smaller capacity than expected	Performance
	Storage capacity below expectations	Performance

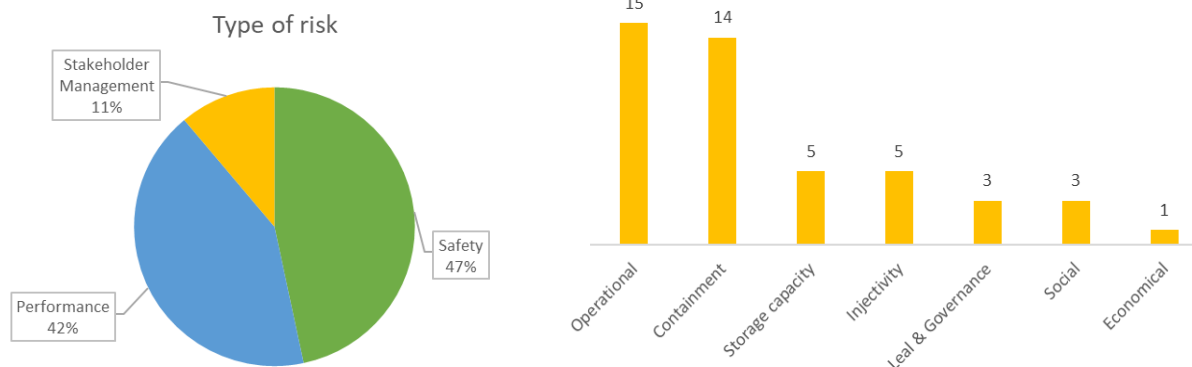


Figure 11: Distribution of generic risk registration by type (left) and by category (right).

### 3.3 Preliminary risk analysis

The preliminary risk analysis refers to the evaluation conducted in Round 1. The work plan of WP5 focused on assessing the **technical risks** (containment, Injectivity, Operational, Storage capacity categories), with the social, economic and legal & governance risks being addressed in WP4 in the scope of the pilot design. The WPs teams were asked to further discard technical risks that are considered **non-existent based on existing knowledge**. Out of the 38 technical risks, **eleven risks** were selected for scenarios analysis in Round 1 (Table 2).

Table 2: Summary of risk groups, scenarios and their classification under the WP5 Risk and Safety Performance framework.

Risk Group	Scenarios	Risk Type	Risk Category
Leakage through well	<ul style="list-style-type: none"> <li>➤ Leakage through operation well</li> <li>➤ Leakage through abandoned well</li> </ul>	Safety	Containment
Leakage due to containment failure	<ul style="list-style-type: none"> <li>➤ Leakage through caprock due to injectivity pressure build up</li> <li>➤ Leakage through caprock due to poor geologic characteristics</li> <li>➤ Leakage through faults</li> </ul>	Safety	Containment
Seismicity related risks	<ul style="list-style-type: none"> <li>➤ Hazards resulting from induced seismicity</li> <li>➤ Leakage as a result of natural seismicity</li> </ul>	Safety	Operational
Fluid- rock interaction	<ul style="list-style-type: none"> <li>➤ Chemical interaction of injected CO<sub>2</sub> with seal (carbonates)</li> <li>➤ CO<sub>2</sub>-seal/fault rock interaction</li> </ul>	Safety Performance	Containment Operational
Injectivity	<ul style="list-style-type: none"> <li>➤ Injectivity below expectations</li> <li>➤ Injectivity loss</li> </ul>	Performance	Injectivity
Storage capacity	<ul style="list-style-type: none"> <li>➤ Storage capacity below expectations</li> </ul>	Performance	Storage capacity

This section presents a descriptive breakdown of the risks flagged during Round 1 for “Round 2 evaluation”. The analysis provides a conservative evaluation of the most relevant risk scenarios for both the pilot-scale CO<sub>2</sub> injection (100kt over 3 years) and the commercial-scale scenario (0.5Mt/yr to 1Mt/yr over 30 years).

Round 1 characterized risks using two approaches:

1) **Bow-tie diagrams** provide a schematic representation of each risk by explicitly linking causes to consequences, while identifying the preventive and mitigative barriers acting within the geological system and the operational design. Their use ensures that the screening process is not based solely on likelihood–impact scoring but is grounded in a **conceptual understanding of causes and consequences of events and on possible prevention and mitigation measures**. This approach is suitable under conditions of limited site-specific data and high uncertainty, as is the case in Round 1.

Bow-tie diagrams are used for consistency with Guidance Document 1 (GD1) of Directive 2009/31/EC, which recommends an initial conceptual representation of risks, barriers, and failure pathways prior to detailed quantitative modelling. This approach is also aligned with the PilotSTRATEGY risk assessment framework described in Deliverable D5.1, where bow-tie diagrams are used to support hazard identification, barrier analysis, and conservative screening under uncertainty.

2) **Risk Analysis** using a quantitative risk approach whenever enough data is available, as suggested in D5.1 (Le Guenan et al, 2022). Otherwise, expert opinion was considered to estimate **Likelihood** and **Impact**.

- Monte Carlo simulations were applied to generate probabilistic risk evaluation from the product of Likelihood and Impact. The simulations were performed with @Risk (Lumivero) with 50,000 realisations to ensure statistical robustness. The Pert distribution was applied for Likelihood and Impact. The use of distributions for both parameters should not be interpreted as independent or additive uncertainties, but as a pragmatic way to capture limited knowledge at Round 1. The likelihood distribution reflects **uncertainty in the occurrence of the scenario** (based on expert judgement and available data), while the impact distribution represents the **range of possible consequences** if the scenario occurs. Their combination

provides an envelope of plausible risk values rather than a strict probabilistic frequency interpretation.

- Whenever there is a higher degree of information or specific tools were being developed in WPs, numerical models were applied, and risk is evaluated from applying those models.

For transparency and regulatory consistency, the transition from quantitative risk estimation (Likelihood × Impact) to the binary classification “Significant” versus “Not Significant” follows an explicit decision rule aligned with the CCS Directive risk management framework and Guidance Document 1 (GD1). A hazard is classified as **Significant** in this report when at least one of the following conditions applies:

- the combination of Likelihood and Impact places the hazard within the “High” or “Very High” zones of the risk matrix<sup>11</sup>;
- the Impact class is assessed as Medium or above and relates to containment integrity, long-term environmental protection, or regulatory compliance;
- material scientific or geological uncertainty remains that may affect the demonstration of “no significant risk of leakage” under Directive 2009/31/EC.

Hazards not meeting these conditions are classified as **Not Significant**, meaning that they do not call into question the integrity of the storage complex or the Directive’s safety objective under the assessed scenarios. The designation of certain commercial-phase hazards as **Significant** does not imply the existence of uncontrolled or unacceptable risks. Rather, it identifies areas requiring continued evidence gathering and risk reduction prior to commercial deployment. This ensures consistency between probabilistic modelling results and regulatory terminology.

The following sections present the risk analysis results.

### 3.3.1 Leakage through wells

The leakage through wells, **either the injection well or abandoned (legacy) wells**, is one of the main containment risks, as any wells drilled through the caprock of the storage formation constitute a potential leakage pathway for CO<sub>2</sub> to escape from the reservoir. The overall contribution of wells to the risk profile depends on the number of operational and abandoned wells.

The assessment of leakage through wells followed the approach in the study *Deep Geological Storage of CO<sub>2</sub> on the UK Continental Shelf: Containment Certainty* (Daniels et al., 2023). Despite the differences between the North Sea offshore settings and the geological and operational context of the northern Lusitanian Basin, adopting the same leakage rate categories ensures comparability and supports a structured evaluation of potential well-related leakage events. Table 3 defines leak severity categories, from Seep (<1 t/d) to Major (>1000 t/d). The methodology assumes that any leakage would be governed primarily by the leak rate and the duration of the event. Due to the small injection rates, only the Seep and Minor leaks cases apply to the Pilot Phase, while the commercial phase considers the four leak rate categories. The risk of leakage from the operational well and from the abandoned well have been addressed separately.

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<sup>11</sup> A risk is classified as **High** when the combination of probability and impact places it in the upper range of the risk matrix and implies a potential challenge to containment integrity or regulatory compliance. A risk is classified as **Very High** when it corresponds to scenarios with both high likelihood and high consequence, potentially compromising the demonstration of “no significant risk of leakage” required by the CCS Directive.

Table 3: Well leak categories according to Daniels et al. (2023).

Category	Leak Rate (t/d)	Description
<b>Seep</b>	Less than 1	Low level nuisance leaks through micro cracks in casing cement or tiny gaps in valves or seals. Whilst there is no minimum reportable leakage rate in the regulations, these may be considered easily dispersed or absorbed into seawater with limited impact on their surroundings. Detected through testing or targeted monitoring. Expected to be unlikely to be remediated once established.
<b>Minor</b>	1 – 50	Failure of well barrier components in active wells or cement plugs in inactive wells resulting in a minor leak that can be addressed by well intervention and component/plug replacement. Detected through regular testing of the pressure build-up/fall-off through barriers or wellhead area monitoring. The leak is resolved within six-months of discovery as securing the equipment required (e.g. a rig) may be deemed non-urgent based on impact. For active leaks the well can usually be shut-in until fixed to either stop the leak or reduce leak rates by reducing the pressure at the leak location. This shut-in would only include the leaking well, injection could continue in the remaining wells.
<b>Moderate</b>	50 – 1000	Similar to the minor leak scenario except that there is an escalation in the rate of the leak. The concentrations of CO <sub>2</sub> could be at a level to make a well intervention unsafe for drill crews. Temporary plugging techniques can usually be deployed on active wells to stop the leak which may allow a well intervention or reduce the volume leaked while mobilising for repair. If the leak rate cannot be stopped or reduced it is assumed that an emergency relief well is required to stop the flow. Typically, it takes four months to drill the relief well as the increased impact of the leak would justify an expedited approach to securing the rig.
<b>Major</b>	Greater than 1000	Represents an unconstrained flow rate. Major leaks are more likely to occur during drilling & well intervention operations but are still rare as well control equipment is installed to prevent uncontrolled flow from the well. A major leak could also be the result of structural failure and so may be difficult to shut in pending repair. The force of release and volumes involved may make it impossible to intervene on the well directly via the wellhead to temporarily or permanently remediate, requiring an emergency relief well to stop the flow. Typically, this takes four months to drill assuming that a rig can be sourced with priority given the severity of the leakage rate.

### 3.3.1.1 Leakage through operation well

Operation wells are defined as CO<sub>2</sub> injectors or observation wells. In PilotSTRATEGY, only one injector is considered, and observation wells are not included as they would be sources of risk of leakage.

Injection wells are designed to have multiple barriers to protect the surrounding environment from contamination by produced or injected fluids, and to prevent flow between different subsurface formations. Well barriers are important risk management elements and can be passive (e.g. casing, packers, cement) or active in enabling or preventing flow (e.g. valves). In best practice of well design for CO<sub>2</sub> injection, performance standards are established for each barrier and barrier element to ensure the hazards and risks associated with the well construction, operation and decommissioning can be managed. As shown in the bow-tie diagram (Figure 12), the consequences lie essentially with the amount of CO<sub>2</sub> leaked and costs associated with possible need for shut-in and workover or even drilling additional well.

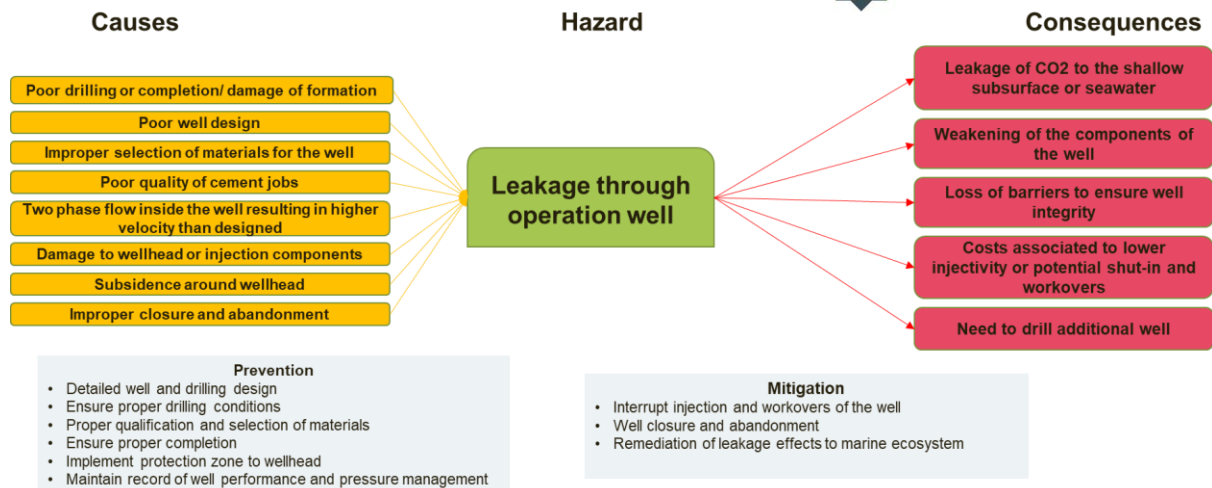


Figure 12: Bow-Tie diagram to identify key causes, preventive barriers, potential consequences, and mitigation measures for the risk of leakage through injection well.

The topic of potential leaks from CO<sub>2</sub> injection wells has been subject of several studies over some decades, with CO<sub>2</sub> injection having already a track record of 53 years for enhanced oil recovery and 29 years for CO<sub>2</sub> storage. There is also a variety of studies on leakage from oil and gas wells from fugitive emissions, loss of integrity data and major loss of containment events. Literature review by Daniels et al. (2023) indicates approximate likelihood for the injection well leaks listed in Table 3:

- Seeps: 0.1% to 10% chance per well of continuous minor leakage (lifetime);
- Minor: 0.001% to 0.1% probability of occurrence per year;
- Moderate: 0.001% to 0.01% probability of occurrence per year;
- Major: 0.0001% to 0.01% probability of occurrence per year.

The impact is provided by the mass of CO<sub>2</sub> ( $M_c$ ) that would leak, quantified as the product of the leak rate and the duration of leakage event in the single injection well. The risk is the percentage of leaked CO<sub>2</sub> with respect to the total injected CO<sub>2</sub> in 3 years for the pilot phase and in 30 years for the commercial phase. Pert distributions<sup>12</sup> were used to represent the distributions of likelihood and impact, with most likely value in the centre of the interval. No significant well integrity derisking will result from the pilot to the commercial phase, as these risks are time-dependent. However, the pilot will provide substantial system-level derisking, particularly through improved understanding of plume behaviour and pressure evolution.

<sup>12</sup> The PERT distribution is a smoothed form of the triangular distribution, defined by minimum, most likely, and maximum values, and commonly used to represent uncertainty in expert-based estimates. See: [https://en.wikipedia.org/wiki/PERT\\_distribution](https://en.wikipedia.org/wiki/PERT_distribution)

Probability density functions for risk of leakage through the operational injection well are shown in Figure 13 for two categories (*minor leak* and *major leak*) in Table 3, with all other categories having lower risks. Across all scenarios, the overall risk remains low to very low, with the impact of leakage through the well being less than 0.01% of the total injected mass.

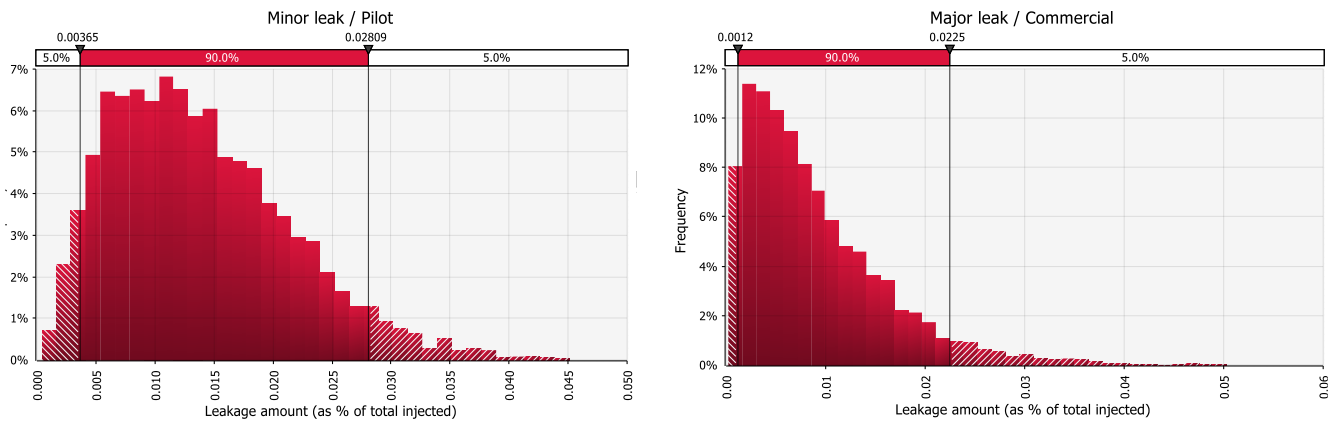


Figure 13: Probability density function of risk of leakage quantified as percentage of the total injected CO<sub>2</sub>, in the *Minor leak* category of the *Pilot Phase* (left) and in the *Major leak* category of the *commercial Phase*. All other leak categories in Table 3 retrieve even lower risks. X-axis and -axis scale vary in the two charts.

However, although the impact in terms of amount of CO<sub>2</sub> leaked is minor, the same cannot be about other consequences illustrated in the bow-tie diagram (Figure 12), such as the costs to drill an additional well or the costs for shut-in and workovers in the event of a moderate or major leakage. In that respect, the impact is high to very high. Nevertheless, the likelihood of a moderate/major events being very low (<0.01%/yr), the risk qualifies as **Not significant** for the pilot phase and the commercial phase and is not addressed in Round 2.

Risk scenario	Key findings	Risk Evaluation
<b>Leakage through operation well</b>	The percentage of leakage that could occur is less than 0.01% for the pilot phase and for the commercial phase, but the costs of workovers or drill a new well would be prohibitive for the pilot phase and significant for the commercial case. However, likelihood of a major leak is very low, lower than 0.01%.	Not significant.

### 3.3.1.2 Leakage through abandoned well

Well Do-1C, located roughly at 11.7 km north from the proposed CO<sub>2</sub> injection well (Figure 2), is the only abandoned well close to the storage site. It represents a potential pathway for CO<sub>2</sub> leakage, in case the CO<sub>2</sub> plume reaches it. This scenario depends on the CO<sub>2</sub> plume extent, the integrity of well seals, and the characteristics of the surrounding formations. Figure 14 presents the bow-tie diagram illustrating the main causes and potential consequences associated with this leakage scenario.



Figure 14: Bow-tie diagram to identify key causes, preventive barriers, potential consequences, and mitigation measures for the risk of leakage through an abandoned well.

The abandonment programme of Do-1C included several cement plugs, heavy-mud intervals, and multiple casing cuts, reflecting the operational standards of the 1970s. These barriers include a 163-sack cement plug in the upper wellbore, cement plugs inside the 13 $\frac{3}{8}$ " and 9 $\frac{5}{8}$ " casings, and a deep cement plug between 2324m–2415m (Figure 15). There is no information about the status of the well, of its cements and casing. In a more conservative view, it should be expected that the cements and material used in the plug and abandonment are not adequate for water acidified due to CO<sub>2</sub> dissolution. A worst-case scenario considers that a well abandoned 50 years ago will leak if the CO<sub>2</sub> plume reaches it. The risk then becomes a function of the **likelihood that the plume reaches Do-1C** with the **impact being the CO<sub>2</sub> saturation** when it reaches the plume, as this relates directly to the leak rate.

During Round 1, WP2 had already characterised the structural features and petrophysical parameters of the reservoir. Hence, a preliminary dynamic modelling assessment using the TOUGH2® simulator supported the risk analysis. The evaluation examined whether the CO<sub>2</sub> plume could migrate towards the abandoned exploration well Do-1C, based on the average petrophysical parameters of an assumed homogeneous reservoir, with an anisotropy factor of 10 ( $k_h/k_v$ ). Simulations were run for the pilot case and for the commercial case, with injection periods of respectively 3 years and 30 years, and simulation times of 1000 years.

Figure 16 illustrates one such simulation for  $k_h=300$  mD and effective porosity  $n_e=15\%$ . In the pilot-scale scenario, the CO<sub>2</sub> plume remains confined in the vicinity of the injection area, while in the commercial-scale scenario, after 1000 years the plume exhibits northward migration but remains more than **3 km** away from the abandoned well and with a CO<sub>2</sub> saturation below 0.1, implying that it would not leak in any case. Therefore, there is **no risk for the pilot phase**, and the risk is very low for the commercial phase.

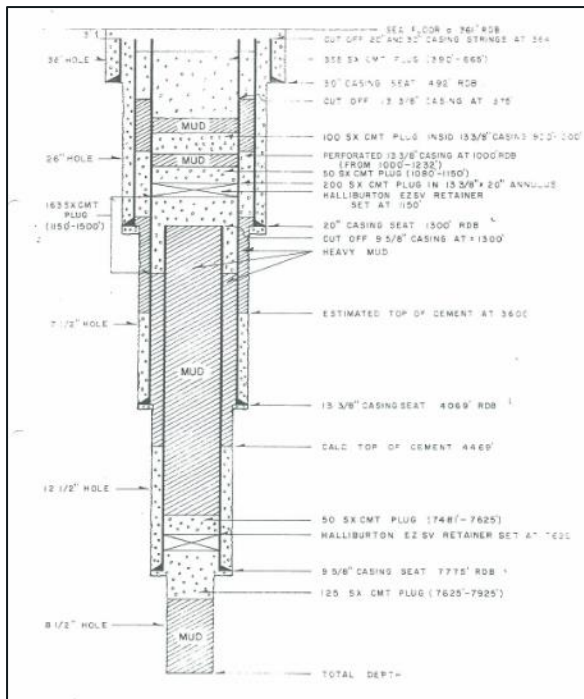


Figure 15: Plug-and-abandonment schematic of the Do-1C well showing cement plugs, casing cuts, and mud-filled intervals installed during abandonment. Reservoir extends from 878m to 1243m (2881ft to 4078ft) depth. Source: PSOC (1975).

However, there is considerable uncertainty in the key parameters that constrain CO<sub>2</sub> plume movement, particularly in what regards the mean permeability of the reservoir (Figure 17). Additionally, the utilised homogeneous model does not represent the complexity of the reservoir and the possibility of the plume reaching high-permeability sand channels. Thus, the risk of leakage through the abandoned well should be addressed in detail during **round 2 for the commercial phase**, since it is **Not significant** for the pilot phase.

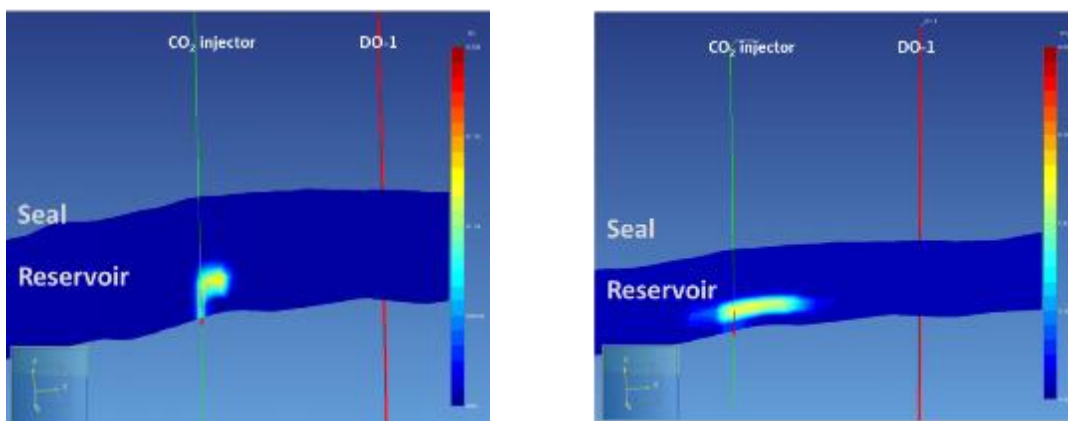


Figure 16: CO<sub>2</sub> free gas plume dispersion for the pilot phase (left) and the commercial phase (right).

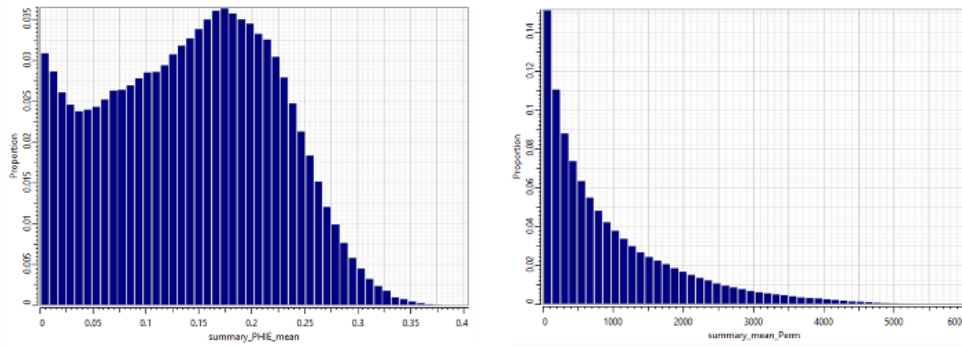


Figure 17: Distributions of porosity (left) and permeability (right) of the reservoir.

Risk scenario	Key findings	Risk Evaluation
<b>Leakage through abandoned well</b>	During the pilot phase, the plume is too small to reach the well Do-1C and even if it reaches the well, the impact would be negligible as the CO <sub>2</sub> saturation would be very low. For the commercial phase detailed analysis is required.	Pilot phase: Not significant Commercial phase: Round 2 analysis

### 3.3.2 Leakage due to containment failure

Leakage due to containment failure is analysed in three scenarios:

- i. Leakage through caprock due to pressure build up, leading to loss of mechanical integrity of the primary caprock;
- ii. Leakage through caprock due to poor geologic characteristics, such as localised high permeability, poor lateral continuity of the caprock and localised low capillary pressures;
- iii. Leakage through faults, providing pathways through the seal, possibly to the seabed.

These risks are not expected to remain constant throughout the life of the storage site. The geological containment risk profile starts at zero, but as increasing amounts of CO<sub>2</sub> are injected, the pressure increases and the plume spreads, the probability of a leak and its impact increases during the injection period (higher pressures, higher CO<sub>2</sub> saturations and larger plumes). Sometime after stopping injection, risks start decreasing as pressure decreases, and residual and dissolution trapping relevance increase to reduce the mobility and size of the plume.

#### 3.3.2.1 Leakage through caprock due to pressure build up

Pressure build up can lead to leakage through the caprock due to (Figure 18):

- Pressure exceeds a critical threshold for which existing faults may slip or be reactivated, or new fractures in the caprock may be created.
- CO<sub>2</sub> pressure exceeds the capillary pressure in the caprock, allowing for CO<sub>2</sub> to penetrate in the caprock and providing the opportunity to reach higher permeability areas.

The bow-tie diagram (Figure 18) illustrates that injection-induced overpressure is the primary initiating cause, with leakage of CO<sub>2</sub> to the layers above the primary seal being the consequence. Conservative pressure limits, multi-layer sealing, and operational pressure can effectively prevent mechanical failure of the caprock at pilot scale.

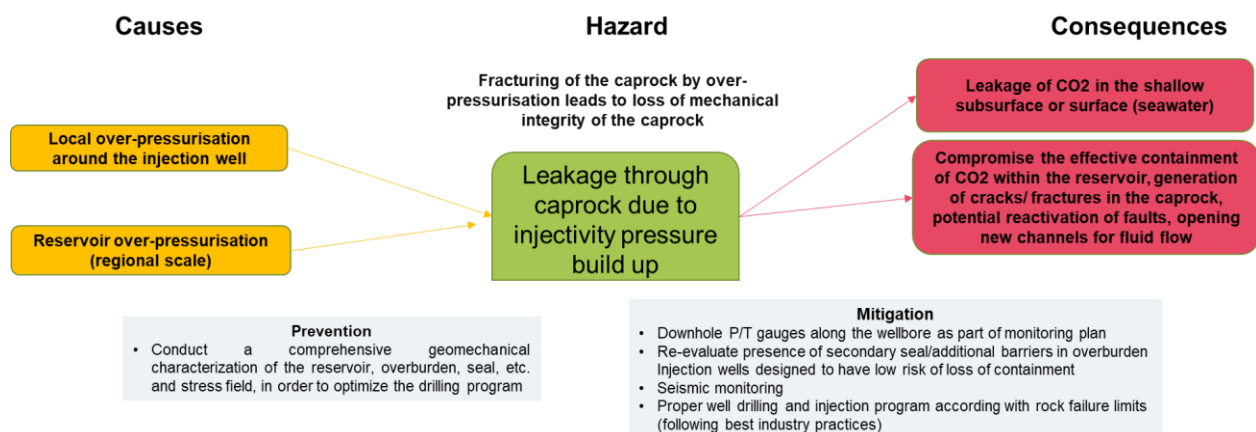


Figure 18: Bow-tie diagram to identify key causes, preventive barriers, potential consequences, and mitigation measures for the risk of leakage through caprock due to injectivity pressure build up

There are no reported geological leaks to surface from any current or former CCS project. Hence, calibrating leakage risk probabilities and magnitudes cannot be established from operational CO<sub>2</sub> injection sites. We chose to resort again to Daniels et al., 2023, which assesses likelihoods and CO<sub>2</sub> leak rates from the storage complex via geological pathways, considering: published articles; analogue

scenarios (including natural gas storage sites, petroleum reservoirs, naturally occurring CO<sub>2</sub> accumulations); preliminary modelling and expert opinion.

Not all the leakage pathways through the caprock will result in a leak to the seabed but if they do, the resulting leaks are likely to be diffuse. Daniels et al. (2023) cites leakage rates of less than 1 t/day/km<sup>2</sup> for diffusion and capillary flow leaks. However, these are very slow processes in fine-grained lithologies, in which leakage might occur over geological time (after thousands to millions of years for a 100 m thick seal), but not over shorter timespans. Since the caprock is at least 70 m thick in the target site and that the secondary seal is even thicker, it is safe to consider that **diffusion and capillary flow do not pose any risk** for both the pilot and commercial phases.

Leakage through faults undetected in the seismic surveys (sub-seismic scale faults), faults by the injection and fracture network leaks can pose a risk. The leak rates from Daniels et al. (2023) are shown in Table 4. The leak rate can be converted into Impact by quantifying the mass of CO<sub>2</sub> that would leak in 3 years (pilot phase) and over the period of injection operations (30 years) plus 100 years post-closure (commercial phase). The likelihood results from expert opinion amongst team members about the probability of the CO<sub>2</sub> plume encountering transmissive faults that crosses the entire seal up to the seabed (not detected in the seismic surveys, but possible since not all of the target site is covered by 3D seismics). Pert distributions were used to likelihood and impact, with most likely value in the centre of the interval.

Table 4: Leak rate and probabilities for leakage through faults, adapted from Daniels et al. (2023)

Category		Leak rate (t/day)		Likelihood of transmissive faults crossing the seal up to the seabed
		max	min	
Sub-seismic scale faults & fracture network	seep	1.0	0.027	Pilot: 0.01; Commercial: 0.1
	minor	2.7	1.0	Pilot: 0.01; Commercial: 0.1

The risk is the percentage of total injected CO<sub>2</sub> that would leak in 3 years for the pilot and in 130 years for commercial phase and is presented in Figure 19. The risk of leakage during the pilot is always much lower than 1% of the total injected, and even for the commercial phase the risk is lower than 1.8% for the 90% percentile (i.e., more than 98.2% of the injected amount would remain sequestered in the reservoir).

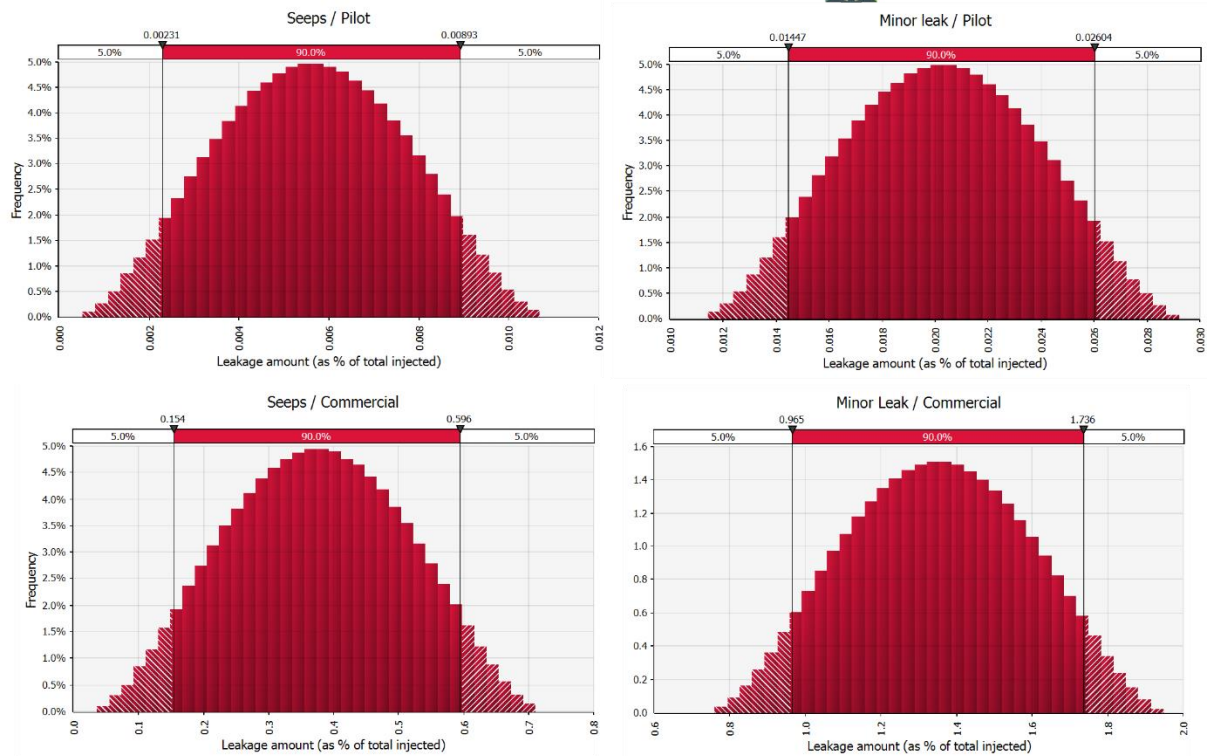


Figure 19: PDFs of leakage risk quantified as percentage of the total injected CO<sub>2</sub> that would leak through undetected fractures due to pressure buildup in the pilot phase (top) and in the Commercial Phase (bottom), for the Seep (left) and the Minor Leak (right) categories.

Therefore, the risk of leakage due to pressure build up inducing diffusion, capillary flow or migration along sub-seismic faults, fracture network or small-scale induced fractures is considered **Not significant** for the pilot. Still, the knowledge about the risks imposed by the pressure build up during the long-term injection in the commercial phase is a function of the **initial reservoir pressure**, something that there is no information about. Given that uncertainly, this risk is flagged for revision in Round 2 for the commercial phase.

Risk scenario	Key findings	Risk Evaluation
Leakage through caprock due to pressure build up	Percentage of CO <sub>2</sub> that can leak due to pressure build up through undetected faults is less 0.1% for the pilot phase. In the commercial phase, the amount that could leak is below 2%. Impact would be higher in the pilot phase, as it would question the feasibility of upscaling., but a moderate public acceptance impact could result for the commercial phase.	Pilot phase: Not significant Commercial phase: Round 2 analysis

### 3.3.2.2 Leakage through caprock due to poor geologic characteristics

The primary seal is composed mainly by limestones at the top and marls and dolomites and clays at the base (see section 2.3). Based on the seismic interpretation, the sealing layer is expected to extend across all the full extent of site, although facies variation is not captured in seismic. Data derived from boreholes that penetrate the seal can provide important constraints on seal properties, but the number of boreholes in the target area is small, and in areas further away from the boreholes there is a risk of reduction in seal quality due to lateral facies changes.

Figure 20 shows the corresponding bow-tie diagram, representing uncertainties related to caprock heterogeneity and undetected higher-permeability zones as initiating causes, with site characterisation and high-quality geophysical data acting as preventive barriers, and monitoring and stop of injection limiting the consequences of a potential leak.

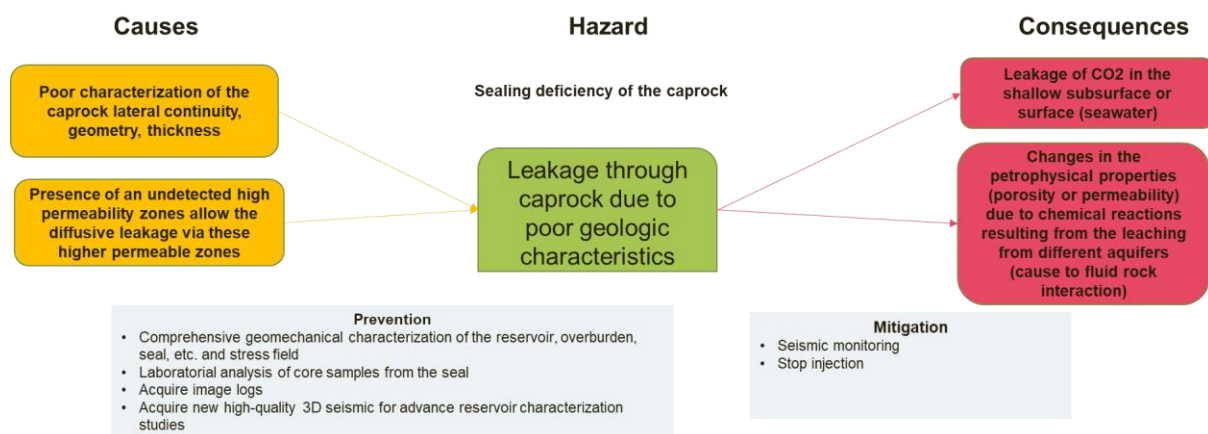


Figure 20: Bow-Tie diagram to identify key causes, preventive barriers, potential consequences, and mitigation measures for the risk of leakage through caprock due to poor geologic conditions.

The CO<sub>2</sub> plume dispersion modelled at the pilot-scale is very small, unlikely to reach the top of the reservoir and get in contact with the seal. However, for the commercial-scale scenario, a larger plume footprint increases the possibility of encountering areas where seal quality may vary due to facies transitions, diagenetic changes, or local heterogeneities. The risk results from the data scarcity and potential undetected heterogeneities. Expert opinion in Round 1 considered that, for the pilot phase, likelihood is Very Low, since the CO<sub>2</sub> plume will be concentrated around the injection well (Figure 16) and may not even reach the top of the reservoir. The impact would be high, not due to the amount of CO<sub>2</sub>, which would be irrelevant, given the small amounts injected, but because it would prove that the storage complex would not be reliable.

However, to fully assess this risk, one must consider the full scope of stochastic models built for the dynamic simulations in WP3. Thus, the specific risk of *Leakage through caprock due to poor geologic characteristics* is considered relevant both for the pilot phase and the commercial phase and is analysed in detail in Round 2.

Risk scenario	Key findings	Risk Evaluation
Leakage through caprock due to poor geologic characteristics	The risk results from the data scarcity and potential undetected heterogeneities.	Round 2 analysis for both pilot and commercial phases.

### 3.3.2.3 Leakage through faults

Existing faults can increase the risk of CO<sub>2</sub> migrating upward, potentially reaching shallow aquifers or the seafloor. Leakage risk depends on whether fluids will reach the pre-existing faults and that the faults are permeable along its length (Figure 21).

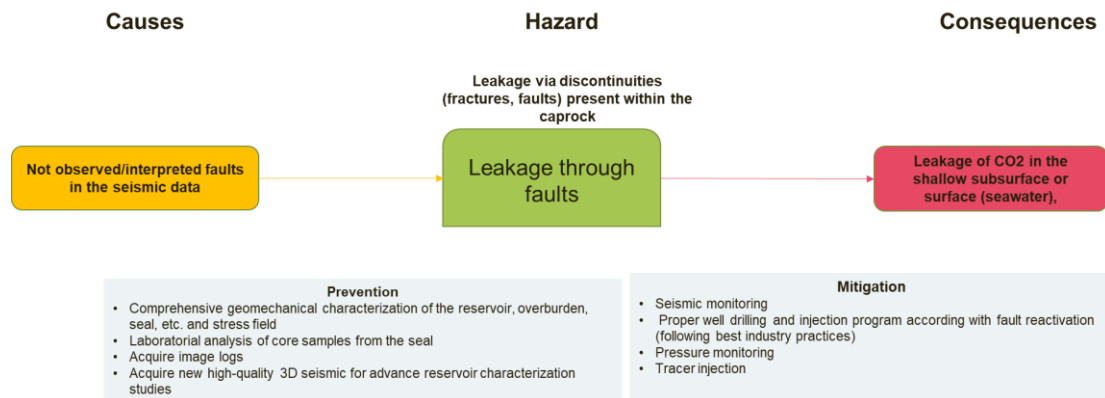


Figure 21: Bow-Tie diagram to identify key causes, preventive barriers, potential consequences, and mitigation measures for the risk of leakage through faults

Fault interpretation was based primarily on the 3D seismic volume, complemented by additional 2D profiles to trace fault continuity beyond the limits of the 3D survey. Within the immediate injection area, no major faults have been mapped but, in the larger domain surrounding it, two fault zones were identified at about 8.9 km and 11 km from the injection well (section 2.4). The risk then becomes a function of the likelihood of the CO<sub>2</sub> plume reaching those faults, as was the case for the risk of leakage through the abandoned well Do-1C.

The spread of the plume was assessed with the TOUGH2 numerical model described in section 3.3.1.2 when evaluating the risk of leakage through an abandoned well. Parameters and setup of the model were the same. Has evidenced by the plume spread in Figure 16 (page 29), the CO<sub>2</sub> does not move in the direction of the faults and the distance travelled would in any case be too short.

We can safely say that there is no risk for the pilot phase. Even for the commercial phase, and although a wider plume dispersion is anticipated the probability of the plume reaching the identified faults is negligible. Therefore, this risk is classified as **Not significant**, for the pilot phase. Still, given the larger volumes injected and the extent of the CO<sub>2</sub> plume, the risk evaluation for the commercial phase is revisited in Round 2.

Risk scenario	Key findings	Risk Evaluation
Leakage through faults	During the pilot phase, the plume is too small to reach the mapped faults. For the commercial phase detailed analysis is required.	Pilot phase: Not significant Commercial phase: Round 2 analysis

### 3.3.3 Seismicity related risks

Seismicity related risks encompass **natural seismicity**, which is well known and characterised by instrumental seismic records, and **induced seismicity** due to pressure build up.

#### 3.3.3.1 Leakage due to natural seismicity

Seismic events can, theoretically, compromise the effective containment of CO<sub>2</sub> within the reservoir, by generating cracks / fractures in the caprock, potentially reactivating existing faults, or affect

infrastructure either directly or via tsunamis. The bow-tie associates natural seismic events with potential loss of containment through damage to wells, seals or reactivation of faults.

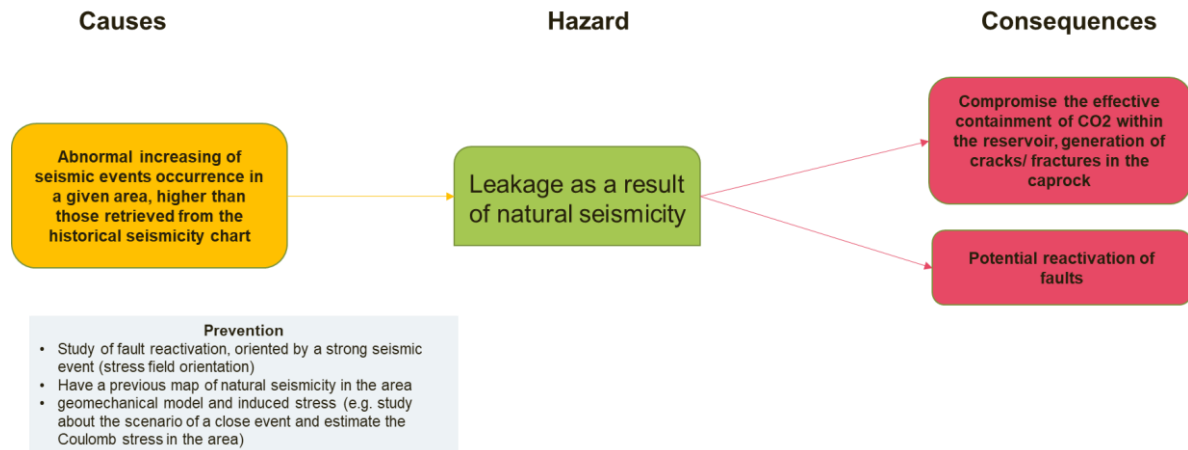


Figure 22: Bow-Tie diagram to identify key causes, preventive barriers, potential consequences, and mitigation measures for the risk of leakage as a result of natural seismicity.

The available information and mapping existent for seismicity is presented in section 2.5. The Eurocode 8 framework was used as the basis for the risk assessment of the leakage as result of natural seismicity. Eurocode 8 imposes that structures are designed for an earthquake with a probability of exceeding 10% in 50 years, which corresponds to an average return period of 475 years.

For the pilot phase, lasting for 3 years, the likelihood of such an event is 0.6%. Impact can be assumed from the expected acceleration in EC8 (Figure 9), as 0.6 m/s<sup>2</sup>. Even for a near field type II earthquake, the expected acceleration would not exceed 1.1 m/s<sup>2</sup>. Proper design of the injection infrastructures would ensure low impact, which is in line with the experience with CO<sub>2</sub> injection wells in high seismic risk sites such as Tomakomai in Japan, where a 6.7 magnitude earthquake at 30 km from the injection site, did not cause any CO<sub>2</sub> leak or damage to the infrastructure (Japan CCS Co., Ltd., 2019)

However, for a type II earthquake, a tsunami could result. If coinciding with the period during which the vessel is injecting CO<sub>2</sub> during the pilot phase<sup>13</sup>, it could result in CO<sub>2</sub> leakage due to loss of connection between vessel and wellhead. Even so and given the small amounts of CO<sub>2</sub> being injected in the pilot, lower than 100 kt in total, and in batches of around 650 tons per vessel, the impact will be limited during the pilot phase.

For the commercial scale, over a 30-year period, the probability of an event with a return period of 475 years is around 6%. However, since CO<sub>2</sub> will remain stored indefinitely, such a major earthquake will certainly occur in Portugal (albeit tens to hundreds of kms away from the storage site). Clearly, assessing the hazard imposed by natural seismicity is relevant for the commercial phase and is conducted in Round 2.

Risk scenario	Key findings	Risk Evaluation
Leakage due to natural seismicity	During the 3-year pilot phase, likelihood of a high magnitude earthquake is below 1%. For the commercial phase detailed analysis is required.	Pilot phase: Not significant Commercial phase: Round 2 analysis

<sup>13</sup> During the pilot, injection of CO<sub>2</sub> is done directly from the ship, with no platform being involved. In the commercial scenario, CO<sub>2</sub> is delivered to the wellhead by an offshore pipeline.

### 3.3.3.2 Induced seismicity

Induced seismicity due to uncontrolled pressure build-up that reactivate or initiate faults can damage infrastructure at the surface, imposing additional cost and/or mitigation strategies that may negatively impact the project economics. The bow-tie (Figure 23) links injection-related pressure changes to possible fault reactivation, showing conservative injection strategy and pressure control as preventive barriers, and operational response and seismic monitoring as mitigation should seismic events occur.

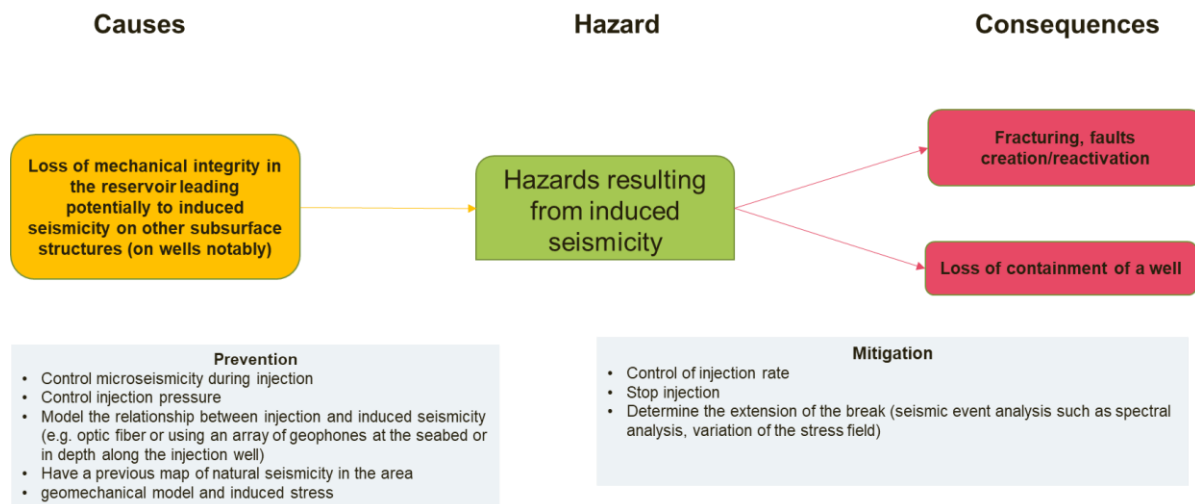


Figure 23: Bow-Tie diagram to identify key causes, preventive barriers, potential consequences, and mitigation measures for the risk of induced seismicity

Induced seismicity hazard was evaluated by considering the expected pressure evolution during injection and the mechanical behaviour of the surrounding geological formations. This is a consequence of the optimization procedure undertaken in WP3, described in deliverable D3.3. The maximum allowable bottomhole pressure (BHP) of 165 bars was defined to ensure that no fracturing of the reservoir or seal is induced.

For the pilot phase, the combination of a relatively small injection rates and short operational duration results in minimal pressure induced in the reservoir, decreasing significantly the possibility of inducing seismicity. Even if it occurred, and precisely because the pilot aims to tests injectivity, immediate decrease/or interruption of injection is perfectly accommodated in the context of the pilot phase.

In the commercial phase, continuous injection will lead to higher pressures, increasing the theoretical potential for induced seismicity. However, the knowledge acquired during the pilot phase will decrease uncertainty about the pressure build up for the commercial phase and will improve pressure management to prevent induced seismicity. This is consistent with observations from international CO<sub>2</sub> storage projects where induced seismicity has been rare. However, impact must be assessed carefully, given the concerns expressed by stakeholders about this risk. Therefore, the risk of induced seismicity during the Commercial Phase and is addressed in detail in Round 2.

Risk scenario	Key findings	Risk Evaluation
<b>Induced seismicity</b>	In the pilot phase small volumes will be injected and intermittency will allow for pressure decline. For the commercial phase detailed analysis is required.	Pilot phase: Not significant Commercial phase: Round 2 analysis

### 3.3.4 Chemical interaction of injected CO<sub>2</sub> with seal

This risk relates to CO<sub>2</sub> reactivity with the caprock, which includes carbonates (marls, dolomites, limestones – see section 2.3). Carbonate dissolution may occur if the dissolved CO<sub>2</sub> plume reaches the seal, depending on fluid composition and pH (Figure 24). When CO<sub>2</sub> dissolves in the formation brine it creates a mildly acidic solution that can dissolve carbonate minerals.

Chemical reactivity of a seal sample (CD-DARN-15) was conducted in WP2 and reported in D2.9 (Kilpatrick et al., 2025) and D2.10 (Mathurin *et al.*, 2026). Sample CD-DARN-15 seal’s upper limestone layer, which is unlikely to contact CO<sub>2</sub> migrating from the reservoir. It is a limestone with calcite (89%) and accessory quartz (7%), kaolinite (2%) and K-feldspar (2%). Batch tests used 5g of crushed material (125–250 µm) in 150–200 ml CO<sub>2</sub>-saturated brine under reservoir P–T for 2 months (see D2.9 for details). Dissolution of the crushed rock was relevant, but the Ca<sup>2+</sup> concentration curve stabilised and dropped, indicating CaCO<sub>3</sub> saturation and secondary amorphous carbonate precipitation, consistent with PHREEQC modelling results (see D2.10). Under natural conditions, water/rock ratios are much lower and rapid saturation from abundant calcite and limited fluid volume greatly restricts bulk rock dissolution in static systems.

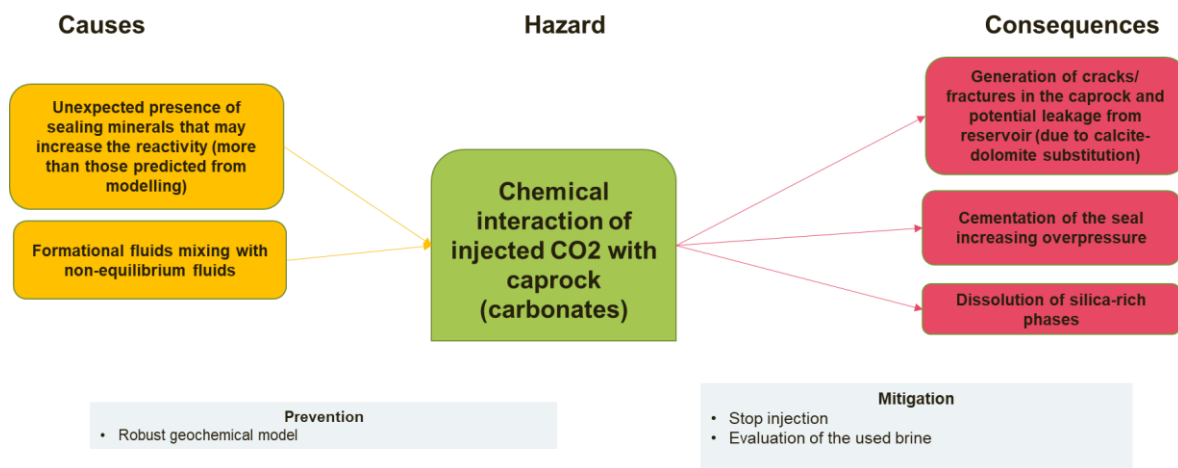


Figure 24: Bow-Tie diagram to identify key causes, preventive barriers, potential consequences, and mitigation measures for the risk of chemical interaction of injected CO<sub>2</sub> with caprock.

Flow-through experiments on the same rock sample simulated dynamic CO<sub>2</sub> injection conditions. A fractured core was exposed to CO<sub>2</sub>-saturated brine for 50 hours (see D2.9). Dissolution occurred but notably subtler than those in the batch experiments. This reflects the tightness of the sample used in the flow-through experiment, limiting the surface area available for reactions (compared to the powdered material in the batch test), better reflecting field conditions.

The tested sample represents the seal’s upper limestone layer, which is unlikely to contact CO<sub>2</sub> migrating from the reservoir. Therefore, results may not reflect the full seal heterogeneity, as its lower sections consist mainly of marl, clay, and dolomite (section 2.3). Furthermore, CO<sub>2</sub> is injected at the reservoir base (>300 m thick). Upward migration is limited by low-permeability clay layers, making caprock contact unlikely during the pilot phase. Even if CO<sub>2</sub>-rich brine reaches the caprock in the commercial phase, rapid carbonate saturation and mineral buffering are expected to constrain dissolution processes, suggesting limited impact on seal integrity.

Nevertheless, even if short-term interactions are minor, long-term chemical effects are uncertain, so the risk of chemical interaction CO<sub>2</sub>/seal is worth further investigation in Round 2 for the commercial phase.

Risk scenario	Key findings	Risk Evaluation
<b>Chemical interaction of injected CO<sub>2</sub> with seal</b>	During the pilot phase, small volumes will be injected and plume may not reach the seal. For the commercial phase detailed analysis is required.	Pilot phase: Not significant Commercial phase: Round 2 analysis

### 3.3.5 Injectivity

An injectivity below the expected 0.5 to 1.0 Mt/yr will impact the operational aspects of the pilot phase and the operational and economic aspects of the commercial phase. Similarly, an injectivity loss along time, for instance due to mineral precipitation will also impact the storage operations. These two risk scenarios are addressed in this section.

#### 3.3.5.1 Injectivity below expectations

Injectivity below expectations implies that the volume of CO<sub>2</sub> that can be injected while maintaining the pressure below the formation fracture threshold, is lower than anticipated, resulting in technical and economic consequences to the feasibility of the project (Figure 25). The mitigation actions are related to decreasing the amount to inject, stimulate the injection well or even drill new wells, and ultimately impact in the costs per ton of CO<sub>2</sub> stored.

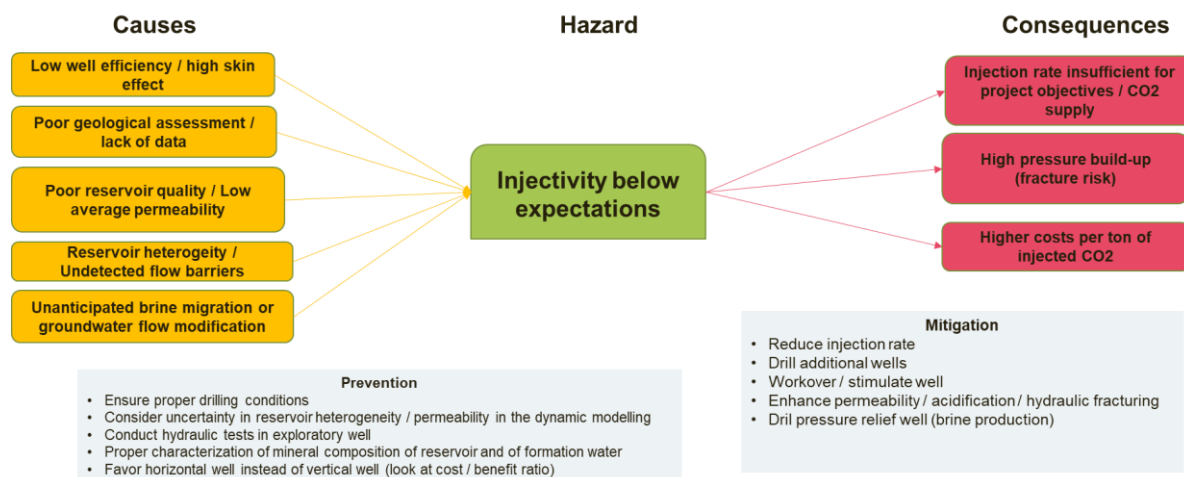


Figure 25: Bow-Tie diagram to identify key causes, preventive barriers, potential consequences, and mitigation measures for the risk of Injectivity below expectations

The impact of the existing uncertainty in the reservoir permeability and heterogeneity was evaluated during injection rate optimization in deliverable D3.3 (Chassagne, 2024). A detailed numerical model of the storage site was implemented in Aspentech's software (Aspen TEMPEST) and a Bayesian optimization algorithm (Bordas et al., 2020) was used with an objective function for maximizing the total injection rate over a 30-year injection period. To account for subsurface heterogeneity, at each well location, 16 parameters of geological uncertainties were varied, including statistical parameters from the interlinked porosity-permeability reservoir models, dependent on lithofacies variations. Further details about the modelling procedure can be found in deliverable D3.3 (Chassagne, 2024). Figure 26 shows the range of total CO<sub>2</sub> that could be injected in 30 years. The key statistics are: P<sub>90</sub> = about 41 Mt (1.37 Mt/yr), P<sub>50</sub> = 18 Mt (0.60 Mt/yr) and P<sub>10</sub> = 4.2 Mt (0.14 Mt/yr).

Figure 26 also depicts the range of CAPEX and OPEX for the injection well designed in WP4 and for which the details are provided in deliverable D4.11 (Canteli, 2026).

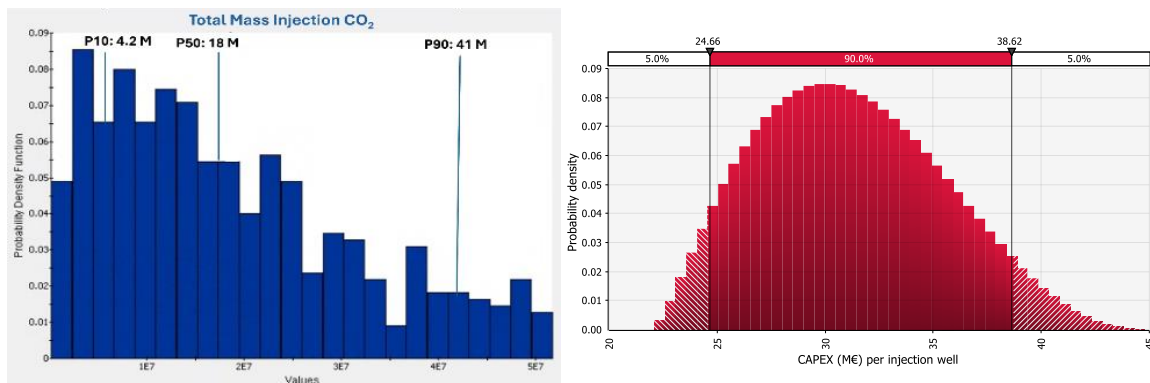


Figure 26: Distribution of total CO<sub>2</sub> mass injection over a 30-year period (left) and distribution of CAPEX (M€) for a single well (right). OPEX are 5% of CAPEX.

Given that the pilot phase aims at injecting 0.1 Mt over a period of three years (if feasible only in one year), the expected injection rate for the pilot phase will then be from 0.03 Mt/yr to 0.1 Mt/yr. The likelihood that injectivity is below expectations in the pilot phase is lower than 10%. Furthermore, Impact relates to the length of time required to inject the same volume since even a very low injection rate still meets the pilot aim to test the reservoir injectivity.

As for the commercial phase, the injection rate being considered ranges from 0.5 Mt/yr to 1.0 Mt/yr, which is consistent with the **central tendency of the distribution (P50, median)** shown in Figure 26.

Likelihood was considered for the number of wells required to inject at least 0.5 Mt/yr: 1 well – 50%; 2 wells - 30%; 3 wells – 15%; 4 wells – 5%. That is, a maximum injection rate given by P<sub>50</sub> (1 well) and a minimum given by P<sub>10</sub> (4 wells). A discrete distribution was assumed. Impact is the variation in CAPEX+OPEX for the injection wells, considering as input the distribution in Figure 26 for a single well.

The resulting risk distribution is shown in Figure 27, as an increase in CAPEX+OPEX with respect to the scenario with a single injection well.

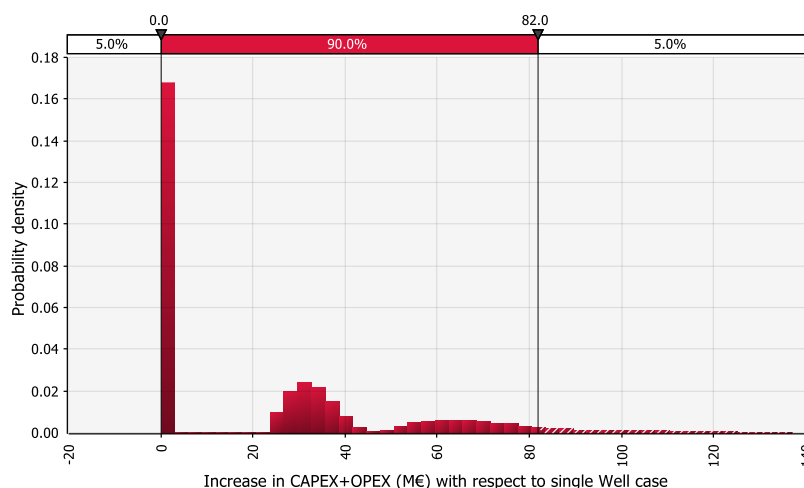


Figure 27: Probability density function for risk of injectivity lower than expected as increase in CAPEX+OPEX in M€ with relation to the single well case.

If multiple wells are required to achieve an injection rate of 0.5 Mt/yr, overall storage costs would increase substantially. This impact is mitigated by the pilot’s purpose of assessing injectivity—which results in lower associated probability densities—and by the fact that the cost increases shown in Figure 27 are far less relevant when evaluating the full-chain costs of the commercial phase.

Risk scenario	Key findings	Risk Evaluation
<b>Injectivity below expectations</b>	During the pilot phase, despite the moderate likelihood (<10%), the risk is residual since assessing the injectivity is an objective. For the commercial phase, the Impact would be high for the costs of storage, but the likelihood is much lower due to data gathered in the pilot.	Pilot phase: Not significant Commercial Phase: Significant

### 3.3.5.2 Injectivity loss

Injectivity loss refers to the progressive reduction in injection rate during operation, typically caused by geochemical precipitation, fines migration, or changes in near-wellbore flow properties. The decrease in injectivity may result in lower well efficiency and higher cost per ton of CO<sub>2</sub> injected (Figure 28).

Geochemical interactions of CO<sub>2</sub>-reservoir-brine was studied through laboratory experiments described in detail in D2.9 (Kilpatrick et al., 2025) and modelled in D2.10 (Mathurin et al., 2026). Reservoir sample CD-CRR-10, a medium-fine sandstone, fine grained, with quartz (91.1%) and K-feldspar (8.9%), was submitted to batch reactivity tests, with 5 g of crushed sample (sieved 125–250 μm) in 150–200 ml CO<sub>2</sub>-saturated brine under reservoir pressure and temperature (P–T) conditions for 2 months (see D2.9 (Kilpatrick et al., 2025) for details). There was no evidence for significant dissolution of the primary mineral assemblage, or secondary precipitation on the timescale of the experiment.

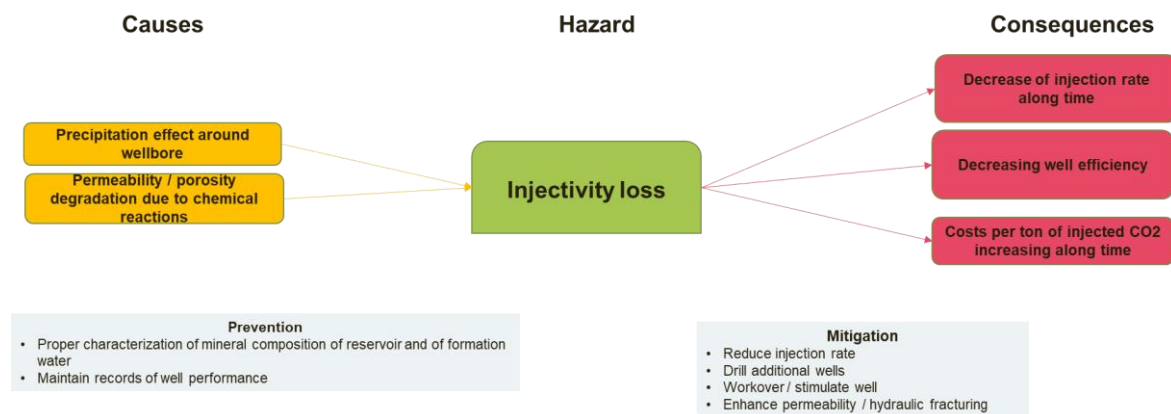


Figure 28: Bow-Tie diagram to identify key causes, preventive barriers, potential consequences, and mitigation measures for the risk of injectivity loss.

Therefore, likelihood of injectivity loss due to mineral precipitation is considered a **Not significant** for both the pilot and commercial phases.

However, there is still the possibility that salt (halite) precipitation caused by water (brine) vaporization around the injection well may have some impact. During the pilot phase, with intermittent and low injection rates, any decline in injectivity due to salt precipitation would have minor operational consequences and is unlikely to restrict the ability to achieve the planned injection rates. Hence, for the pilot phase this risk is **Not significant**.

However, a continuous injection during the commercial phase may lead to salt precipitation and impose operational adjustments—such as rate optimisation, stimulation, or the addition of a supplemental injector - potentially resulting in operational interruptions. Therefore, this risk is addressed through numerical modelling in Round 2.



Risk scenario	Key findings	Risk Evaluation
<b>Injectivity loss</b>	During the pilot phase risk is acceptable as operations are inherently flexible. For the commercial phase detailed analysis is required	Pilot phase: Not significant Commercial phase: Round 2 analysis

### 3.3.6 Storage capacity

#### 3.3.6.1 Storage capacity below expectation

Storage capacity below expectations is a performance risk since it could reduce the commercial interest of the prospect (Figure 29). The consequences would ultimately result in an increase in costs per ton of CO<sub>2</sub> stored. As defined in the FEP database (Savage et. al, 2004) the storage capacity depends on several geological categories, namely the reservoir geometry, the lithology and the petrophysical properties.

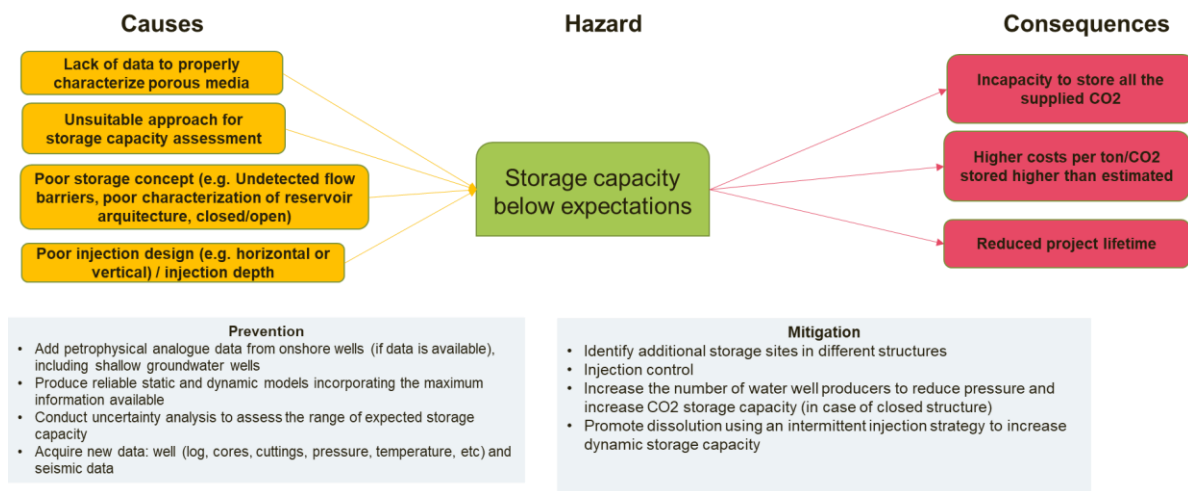


Figure 29: Bow-Tie diagram to identify key causes, preventive barriers, potential consequences, and mitigation measures for the risk of storage capacity below expectations.

The total storage capacity is irrelevant for the pilot phase itself, since only 0.1 Mt are aimed to be injected. Thus, the risk does not exist really exist for the pilot phase.

The uncertainty analysis conducted in D3.2 (Bouquet, 2024) allows to assess the likelihood of storage capacity not meeting the commercial phase expectations of 15 Mt to 30 Mt of CO<sub>2</sub> being injected over 30 years. The analysis applied the volumetric approach to quantify the static storage capacity and considered the variation in the petrophysical parameters that affect the rock porous volume, but also uncertainty regarding the storage efficiency factor, pressure and reservoir temperature. Figure 30 shows likelihood of storage capacity, and indicates a mean capacity of 117 Mt, with P<sub>90</sub>, P<sub>50</sub> and P<sub>10</sub> values of 298 Mt, 158 Mt and 81 Mt, respectively. In fact, the likelihood that storage capacity is below the required 15 Mt to 30 Mt for the commercial phase is below 1% to 2%, respectively.

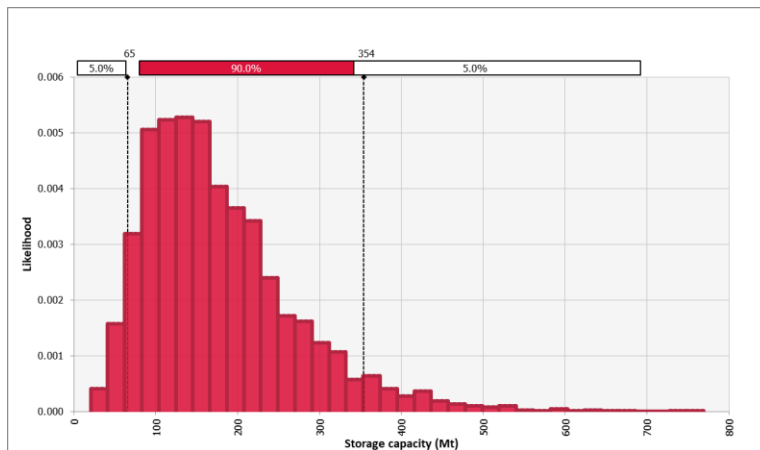


Figure 30: Likelihood of storage capacity based on the volumetric equation in Mt.

The impact is the variation in cost per ton of CO<sub>2</sub> stored, since the investment would result in storing a smaller amount of CO<sub>2</sub>. Given the preliminary costs assessment available at Round 1, a Pert distribution with a minimum cost of 10 €/t, a most likely of 15€/t and a maximum of 20 €/t was admitted for storing 15 Mt of CO<sub>2</sub>.

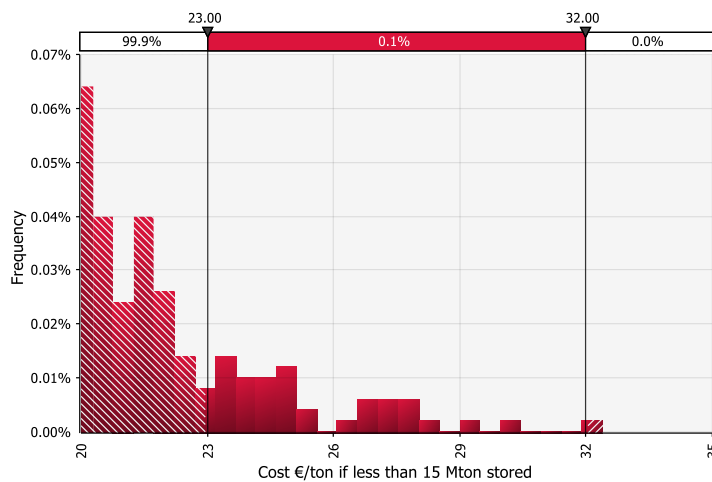


Figure 31: Distribution of risk of storage capacity below expectations as costs per ton of CO<sub>2</sub> stored if less than 15 Mt of storage capacity.

Risk scenario	Key findings	Risk Evaluation
<b>Storage capacity below expectations</b>	Risk does not exist for the pilot phase due to small amount to inject. Likelihood is very low during the commercial phase, even if impact can be very high.	Pilot phase: Not significant. Commercial phase: Significant

### 3.4 Preliminary risk evaluation

The Round 1 preliminary risk evaluation integrates the outcomes from all assessed categories and provides an overall view of the potential risks associated with CO<sub>2</sub> storage in the Lusitanian Basin.

The preliminary risk analysis in the previous section provides a first estimate of the potential risk scenarios and identifies those which are **Not significant** (i.e., no significant risk to safety or

performance according to the GD1) and those that should be addressed in detail in Round 2. Table 6 presents each risk scenario's likelihood and impact for pilot phase vs commercial phase, and the resulting risk evaluation (Not significant or flagged for Round 2).

The qualitative ranking (Table 5) of Likelihood and Impact is adapted from the categories proposed within WP4 by REPSOL.

Table 5: Likelihood and Impact qualitative categories (adapted from REPSOL Projects Risk Management Process)

	Probability				
	Very low	low	Medium	High	Very High
Frequency of occurrence (times/yr)	<1/100	1/100 – 1/10	1/10 - 1	1 - 10	>10
% description	<10%	10% - 40%	40% - 70%	70% - 90%	>90%
Event description	Remote chance of happening	May happen less than once during the project lifetime	Expected to occur in the project lifetime	Expected to occur several times in the project lifetime	Occur once or more per year in the project lifetime
Qualitative description	Rare, very unlikely	Unlikely but not impossible	Possible	Moderately likely	Almost certain, will probably arise

	Impact				
	Very low	low	Medium	High	Very High
CAPEX (% of total investment)	<0.01	0.01 – 0.1	0.1 – 1.0	1 - 10	>10
Schedule (% project duration)	<0.5	0.5 - 5	5 - 10	10 – 20	>20
OPEX (% yearly budgeting)	<0.01	0.01 – 0.1	0.1 – 1.0	1 - 10	>10
Cost increase (% per ton CO <sub>2</sub> stored)	<0.01	0.01 – 0.1	0.1 – 1.0	1 - 10	>10
Environment	Fugitive emissions	Controlled release	Emissions exceed limit	Some damage to environment	Widespread damage to environment
Public image	Individual	Local	Regional	Industry-wide	National / international
Qualitative description	Negligible	Minor, easily remedied	Moderate, some objectives affected	Major, most objectives threatened	Most objectives will not be met

Table 6: Preliminary risk evaluation.

Risk Category	Scenario	Phase	Likelihood	Impact	Risk Evaluation (Not significant*/flagged for Round 2)
Leakage through wells	R1 - Leakage through operation well	Pilot – R1p	Very low	High	<b>Not significant.</b> Well designed to best practices.
		Commercial – R1c	Very Low	High	<b>Not significant.</b> Well integrity tested during pilot.
	R2 - Leakage through abandoned well	Pilot – R2p	Very low	Very low	<b>Not significant.</b> Plume too small to reach Do-1C.
		Commercial – R2c	<b>Round 2</b> – numerical modelling of plume dispersion		
Leakage due to containment failure	R3 - Leakage through caprock due to pressure build up	Pilot – R3p	Very Low	High	<b>Not significant.</b> Pressure management during Pilot.
		Commercial – R3c	<b>Round 2</b> – numerical modelling of containment failure		
	R4 - Leakage through caprock due to poor geologic characteristics	Pilot – R4p	<b>Round 2</b> – numerical modelling of caprock integrity		
		Commercial – R4c	<b>Round 2</b> – numerical modelling of caprock integrity		
	R5 - Leakage through faults	Pilot – R5p	Very low	Very low	<b>Not significant.</b> Plume too small to reach faults.
Commercial – R5c		<b>Round 2</b> – numerical modelling of plume dispersion			
Seismicity related risks	R6 - Leakage due to natural seismicity	Pilot – R6p	Very low	Low	<b>Not significant.</b>
		Commercial – R6c	<b>Round 2</b> – Analysis of seismicity hazard		
	R7 - Induced seismicity	Pilot – R7p	Very low	Low	<b>Not significant.</b> CO <sub>2</sub> volume to inject is small. Intermittent injection allows for pressure decline.
		Commercial – R7c	<b>Round 2</b> – Fault reactivation and probabilistic seismicity analysis		
Fluid – rock interaction	R8 - Chemical interaction of CO <sub>2</sub> with seal	Pilot – R8p	Low	Very low	<b>Not significant.</b> CO <sub>2</sub> volume to inject is small. Plume may not reach the seal.
		Commercial – R8c	<b>Round 2</b> – Modelling of caprock integrity		
Injectivity	R9 - Injectivity below expectations	Pilot – R9p	Medium	Very low	<b>Not significant.</b> Aim of the pilot is to test reservoir.
		Commercial – R9c	Low	High	<b>Significant.</b> Pilot provides additional reservoir data.
	R10 - Injectivity loss	Pilot – R10p	Medium	Low	<b>Not significant.</b> Pilot is adaptable to injection conditions.
		Commercial – R10c	<b>Round 2</b> – injectivity loss modelling		
Storage capacity	R11 - Storage capacity below expectations	Pilot – R11p	Very low	Very low	<b>Not significant.</b> Given the small amount to inject, there is no risk.
		Commercial – R11c	Very Low	Very high	<b>Significant.</b>

\* **Not significant:** risks that do not call into question the purpose of the CCS Directive for the storage site concerned, according to Guidance Document 1.

Scenarios identified flagged in Round 1 through the combined use of bow-tie analysis and likelihood–impact estimations are subsequently examined in Round 2 using detailed numerical modelling and probabilistic analysis, to quantitatively test the robustness of the barriers identified at the screening stage.

Overall, from the 22 scenarios reviewed in Round 1 (11 for the Pilot + 11 for the commercial phase), twelve scenarios were regarded as **Not significant**, two hazards (Injectivity below expectations and storage capacity below expectations) were regarded as **Significant** for the commercial phase and 9 risks are addressed in detail in Round 2. For the pilot phase scenario, the risks remain consistently low due to small injection volumes, short operational duration, and operational flexibility. Only the hazard “*Leakage through caprock due to poor geologic characteristics*” is a concern in the Pilot and is addressed in Round 2. For the commercial phase, higher injection rates, longer operational periods and reduced operational flexibility (due to continuous CO<sub>2</sub> supply) introduce an increase in likelihood and impact of events in injectivity, containment failure or seismicity related risks, requiring a more detailed assessment in Round 2.

### 3.5 Pilot implementation plan

The implementation plan outlines how the CO<sub>2</sub> storage pilot will be carried out in practice, incorporating safety and performance considerations from the risk assessment. It is developed in WP4 and includes several other aspects beyond safety and performance, namely regulatory aspects, well and injection design, operational strategy, and monitoring activities for the pilot phase. Nevertheless, Round 1 of the risk assessment provided recommendations that are included in the pilot plan, including:

- **Regulatory Classification:** The pilot is limited to injection of 100 kt of CO<sub>2</sub>, which classifies it as a research and demonstration project under Portuguese law. This means it is exempt from the full licensing procedures of a commercial storage project (as per DL 60/2012). Nevertheless, the implementation plan must consider the need for a Title for Private Use of Maritime Space (TUPEM) from DGRM to cover the offshore activities;
- **Injection Well and Drilling Plan:** The pilot will utilize a single dedicated CO<sub>2</sub> injection well. No observation / monitoring wells are planned, as they would impose an unnecessary risk. The injection well location has been optimized through modelling to minimize risk of leakage through faults and the legacy well Do-1C. The well will be drilled using best practices, with multiple casing strings and cement barriers adequate to prevent any leakage up the wellbore;
- **Formation evaluation data:** during drilling, formation evaluation data should be collected, for example, coring and logging of the reservoir and caprock intervals, to refine their properties, and measurement of the formation pressure water salinity for baseline data. After drilling, the well will be completed with corrosion-resistant materials and downhole monitoring instruments (such as pressure and temperature gauges) to facilitate continuous data collection during injection;
- **Injectivity tests** given the lack of data about the permeability of the reservoir, an injectivity test with water equilibrated with the reservoir mineralogy should be conducted (as the use of water not in equilibrium with the reservoir and brine could lead to precipitation of minerals and decrease in porosity and permeability);

- **Injection Operations:** The target injection rate during the commercial phase may be up to 1.0 Mt/yr or lower (it may ramp up gradually). The injection will be actively pressure-managed to ensure that bottom-hole pressure stays below defined safety thresholds to avoid fracturing the reservoir or caprock. If monitoring indicates pressure rising too quickly or signs of near-well permeability loss, injection rate will be reduced accordingly.

Overall, Round 1 translated the risk assessment findings into concrete actions and design choices for WP4. By limiting the injection size, defining well location and maintaining operational flexibility, the plan creates a controlled environment to prove CO<sub>2</sub> containment.

The next chapter will synthesize the risk analysis conducted in Round 2.

## 4. Risk assessment synthesis

The Round 2 assessment relies on integrating updated numerical modelling results, Bayesian stochastic analyses, and geomechanical evaluations from WP2, WP3, WP4, and WP5. The refinement process follows a structured workflow that progressively narrows uncertainties and improves the reliability of risk quantification.

### 4.1 Risk analysis

Round 2 incorporates a continuous feedback loop between geological characterisation (WP2), numerical simulation (WP3), pilot development (WP4), and risk and safety performance (WP5). In several cases extensive modelling was done, but for conciseness this section provides a synthesis of the assessment, while detailed analysis is presented as **Appendices** to this report, or in **deliverables D3.4** (Pereira et al., 2026a) and **D3.5** (Pereira et al., 2026b), when the analysis was conducted in the scope of the modelling tasks related to the long-term fate of CO<sub>2</sub> (D3.4) or of the phenomenological impacts for storage (D3.5).

#### 4.1.1 Leakage through abandoned wells

The preliminary assessment in Section 3.3.1.2 evaluated the likelihood of the CO<sub>2</sub> plume reaching the legacy exploration well Do-1C. The assessment indicated that such an occurrence is not possible during the pilot phase and is unlikely during the commercial phase. However, high uncertainty in the petrophysical parameters governing CO<sub>2</sub> plume migration imposed further analysis using the detailed numerical models developed in WP3. The analysis here presented focuses solely on the Commercial Phase, with detailed descriptions of the numerical approach and results provided in **Appendix 2**.

##### 4.1.1.1 Key data and assumptions

The location of the abandoned well Do-1C with respect to the proposed injection well, separated by 11.7 km, is shown in Figure 2 (page 12). Section 3.3.1.2 (page 27) describes the main features of well Do-1C, including its plug and abandonment features in 1975, under standards that differ from present-day CO<sub>2</sub> storage requirements. Potential causes of integrity failure of Do-1C that could lead to CO<sub>2</sub> leakage include degraded cement, incomplete plug placement, subsidence around the wellhead, or corrosion of casing or cement. However, a precondition for this scenario is that the CO<sub>2</sub> plume must reach the Do-1C, thus the risk analysis focused on the likelihood of this occurring.

##### 4.1.1.2 Modelling approach

The modelling approach applied an expanded stochastic simulation framework in the dynamic numerical model to quantify the long-term migration of the injected CO<sub>2</sub> plume over the course of 1000 years (30 years of injection at a rate of 0.5 Mt/yr and additional 970 years of simulation).

A refined geological model was adopted, based on the structural interpretation and petrophysical characterization delivered in WP3, with coarsening of the grid in regions distant from the injection well to allow the simulation of 1100 realizations over a 1000-year time horizon (Figure 32). The stochastic methodology was specifically configured to evaluate the likelihood of plume migration approaching either the legacy well or the faults under wide ranges of uncertainty. Natural throughflow in the reservoir was assumed negligible, since the structure is not connected to any potential recharge area onshore and high salinity groundwater indicates that residence times are very high.

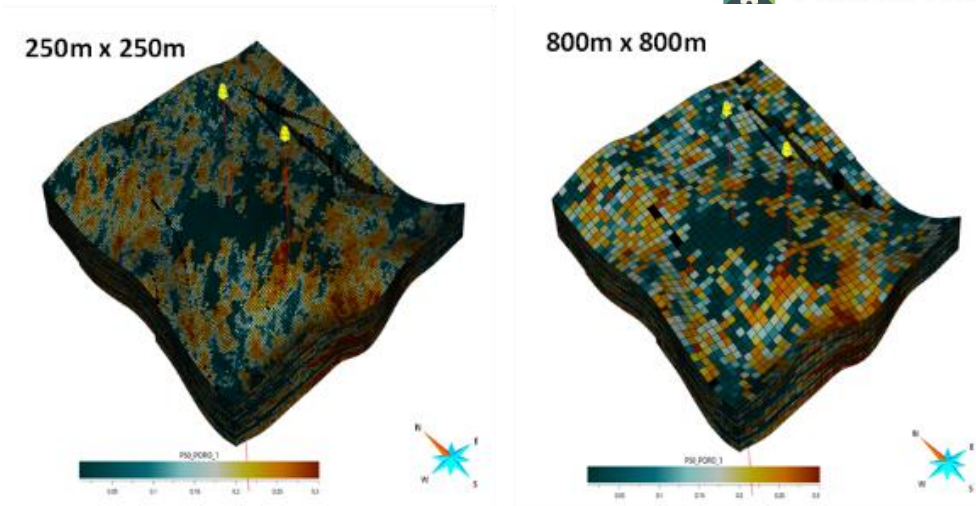


Figure 32: Grid resolutions used in dynamic CO<sub>2</sub> injection modelling. The left model (250 m × 250 m × 10 m) corresponds to the configuration from task 3.3. The right model (800 m × 800 m × 10 m) adopts coarser grid cells to reduce computational time while maintaining representative flow behaviour during the 1000-year stochastic variation analysis.

Modelled uncertainties included porosity, permeability, vertical anisotropy ratios, irreducible water saturation, residual gas saturation, and relative permeability. Each parameter was sampled with either PERT or triangular distributions depending on the certainty and availability of supporting data. All 1100 realizations were generated by sampling from these distributions, allowing adjustments during iterative simulation. For completeness, extreme cases with unlikely high injection rates of 51 Mt CO<sub>2</sub> in 30 years were also investigated.

#### 4.1.1.3 Results

The ensemble of 1100 simulations produced a broad distribution of plume footprints (Figure 33). The free-phase CO<sub>2</sub> plume is never at a distance less than 800 metres of the Do-1C well. Across all realizations, the plume remains structurally confined and **not a single scenario shows the CO<sub>2</sub> plume reaching the DO-1C well**, even for the most extreme scenarios with 51 Mt of injected mass. Furthermore, when the plume for the extreme cases in which the plume is less than 1 km from Do-1C the CO<sub>2</sub> saturation below 0.1, implying that that the risk of leakage does not exist.

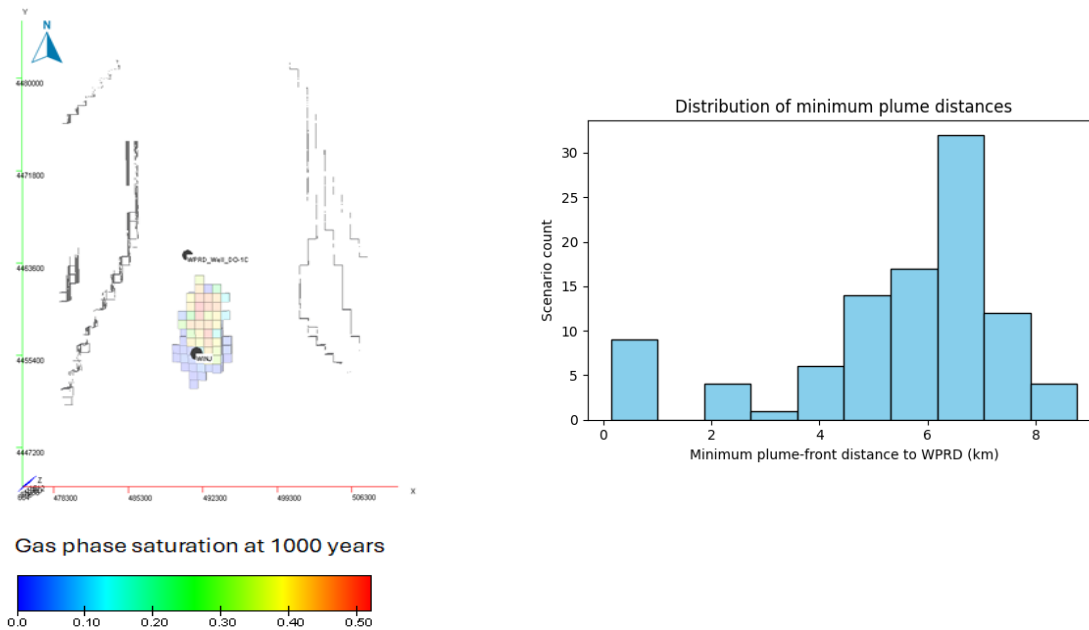


Figure 33: Left) example of free-phase CO<sub>2</sub> saturation at 1000 years for scenario 606 out of the 1100 stochastic realisations, showing the maximum lateral plume extent relative to the DO-1C legacy well in plan view. Right) Distribution of distances between the plume front and the Do-1C abandoned borehole after 1000 years. In all realistic scenarios the plume is never at distance shorter than 800 m from the legacy well and all results below 1 km distance are from the extreme injection rate scenario (51 Mt/yr), imposing higher pressure gradients and faster plume movement.

Consequently, it can be concluded that for commercial phase:

- **Scenario Probability:** Extremely low (effectively negligible).
- **Potential Impact:** No CO<sub>2</sub> leak anticipated.

#### 4.1.1.4 Risk evaluation and recommendations

Based on this analysis, the risk of leakage from an abandoned well is evaluated as follows:

Risk scenario	Key findings	Risk evaluation
<b>Leakage from an Abandoned Well</b>	The CO <sub>2</sub> plume does not reach the nearest well (Do-1C) under any simulated injection scenario, even under conservative modelling assumptions.	Not significant

The analysis confirms that existing wells do not pose a risk under normal storage system evolution. However, to further reinforce this conclusion, the following is recommended:

- **Monitoring of Do-1C:** the MMV plan for the pilot phase delineates a strategy for unambiguously identify the location of Do-1C, resorting to geophysical methods, characterise the baseline around it and plan for regular monitoring during the commercial phase.
- **Redo risk assessment following the Pilot Phase:** the pilot phase will allow to reduce the uncertainty in the petrophysical parameters that govern the CO<sub>2</sub> plume migration. Prior to the commercial phase deployment, the dynamic numerical model should be updated and revisited to confirm the plume migration and reassess the risk of CO<sub>2</sub> reaching Do-1C;
- **Monitoring the CO<sub>2</sub> plume:** during the commercial phase and in accordance with national regulations and the CCS Directive, plume monitoring should consider the location of Do-1C and if it indicates plume movement likely to reach Do-1C, early warning methods, possibly based on SpotLight™, a passive seismic monitoring system, should be implemented.

#### 4.1.2 Leakage through faults

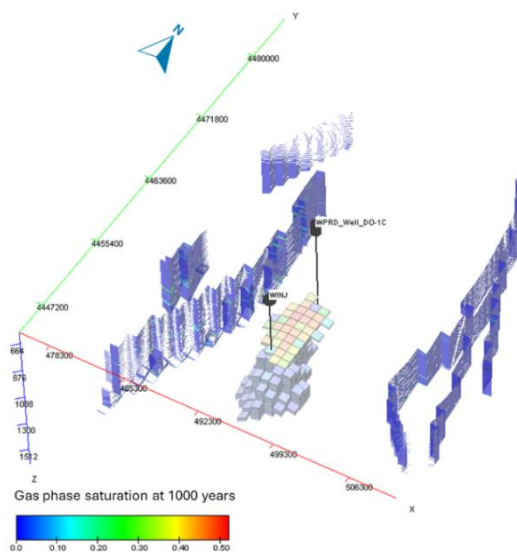
Figure 2 in section 2.4 shows the location of the major faults bounding the storage site, roughly at 8.7km to 11km from the injection well, with the two closest faults being F2 to the east of the injection well, and F5 to the west. Faults strike roughly N–S and NW–SE. If such discontinuities are transmissive, they can provide potential paths for CO<sub>2</sub> leakage if the plume reaches them. This risk was deemed Not significant in section 3.3.2.3, but since it can be assessed with the same numerical model used to verify the risk of leakage through well Do-1C in the previous section, we address it here again. Appendix 2 includes detailed analysis, while we present here a summary.

##### 4.1.2.1 Key assumptions and data

Interpretation of 2D and 3D seismic surveys admit that the faults may extend up to the seabed, but there is no indication whatsoever about the permeability along the faults, although the fact that they are normal faults may favour the existence of meaningful permeability. Thus, stochastic modelling considered scenarios of fault totally impermeable to scenarios of permeability equal to the reservoir. Nevertheless, the precondition is dictated by the risk of the CO<sub>2</sub> plume reaching faults not only during the CO<sub>2</sub> injection (30 years) of the commercial phase, but also for longer periods (1000 years) to check if the plume immobilizes.

##### 4.1.2.2 Modelling approach

The same stochastic methodology applied to assess plume migration toward the legacy well in the previous section was deployed here to evaluate the likelihood of CO<sub>2</sub> reaching the major bounding faults up to 1000 years after injection.



##### 4.1.2.3 Results

Across all 1100 realizations, the plume remains contained within Q4-TV1 prospect and does not reach the mapped faults on either side of the reservoir. Figure 34, shows an example of plume extent and CO<sub>2</sub> saturation remaining several kms away from the mapped fault. No realization indicates plume contact with these faults, confirming that the reservoir–fault system remains effectively hydraulically isolated under all plausible modelling realisations, even for those in which the faults are as permeable as the reservoir itself.

Figure 34: Example of 3D view of free-phase CO<sub>2</sub> saturation at 1000 years for scenario 606 out of the 1100 stochastic realisations, illustrating plume geometry and vertical distribution relative to the faults.

##### 4.1.2.4 Risk evaluation and recommendations

Based on these results, there is no risk of CO<sub>2</sub> reaching the faults and causing leakage, and no specific monitoring procedures are recommended other than tracking the CO<sub>2</sub> plume during the commercial phase.

Risk scenario	Key findings	Risk evaluation
<b>Leakage through Faults (Commercial phase)</b>	The CO <sub>2</sub> plume does not reach the mapped faults under any simulated injection scenario, even under conservative modelling assumptions.	Not significant

### 4.1.3 Containment failure due to pressure buildup

Containment failure refers to the loss of seal integrity, potentially allowing CO<sub>2</sub> to migrate upward if reservoir pressures exceed the mechanical limits of the overlying formations. The risk of geomechanical failure of the caprock may occur due to pressure build-up in the storage complex, particularly pressure propagation from the reservoir into the caprock. This is more critical during the 30-year injection period, although understanding and assessing the geomechanical behaviour in the first years of the post-injection period is also important. This risk was evaluated through numerical modelling in WP3, and the approach and results are described in detail in **Deliverable D3.5** (Pereira et al., 2026b). The following section presents a summary of the work conducted.

#### 4.1.3.1 Key data and assumptions

The evaluation of the structural integrity of the CO<sub>2</sub> storage complex is centred on the geomechanical characterization of the Cacém Formation, recognized as the regional sealing unit (caprock). Consisting of Upper Cretaceous carbonated rocks, it isolates the top of the reservoir from the overlying Aveiro Group (Figure 35), which acts as a potential secondary seal (caprock) and the first geological layers of the overburden. The 3D geological model initialization assumed a local geostatic equilibrium condition. The timeline of the mechanical analysis was segmented into two distinct phases:

- Operational Phase (Injection): 30-year duration;
- Shut-in Phase (Post-Injection): 70-year period to assess system stabilization and relaxation.

To validate seal robustness and perform an uncertainty analysis, the following scenarios were studied:

- Reference Case: Injection rate of 0.5 Mt/yr through a single well.
- High Injection Scenario: Injection rate increase to 1 Mt/yr, evaluating single-well versus dual-well configurations (i.e., one perforation intervals versus two perforation intervals in the same injection well for CO<sub>2</sub> injection).
- Sensitivity Analysis: Systematic parametric variation of mechanical parameters - cohesion (0.1, 1 and 5MPa), friction angle (10°, 20° and 30°), Young's modulus (5, 33 and 60 GPa), and Poisson's ratio (0.2, 0.29, 0.4), focused on the most critical scenario previously assessed (i.e., the injection rate of 1 Mt/yr using two perforation intervals).

Importantly, it is assumed that the initial reservoir pressure is assumed to be hydrostatic, as there is a complete lack of data about the in-situ pressure conditions.

#### 4.1.3.2 Modelling approach

The modelling methodology adopted a coupled thermal-hydraulic-mechanical (THM) approach to simulate the rock mass response to effective stress state changes induced by fluid injection.

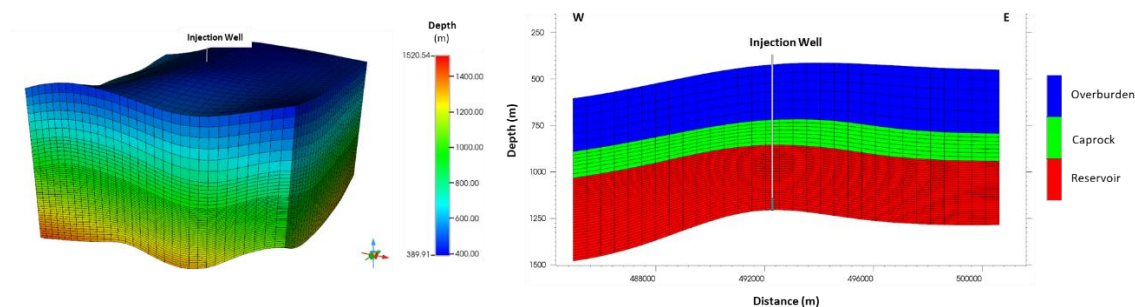


Figure 35: 3D geological model and corresponding W-E cross-section of the storage complex near the injection well, illustrating the succession of main model units: reservoir (red), caprock (green), and Aveiro Group overburden (blue).

The structural stability assessment was grounded on the Mohr-Coulomb failure criteria which enables the determination of the maximum shear strength of the material as a function of effective normal stress. System safety was quantified via the Factor of Safety (FS), defined by the relationship between the acting stress state and the failure envelope.

#### 4.1.3.3 Results

The integrated geomechanical assessment validates the adequacy of the CO<sub>2</sub> storage complex, confirming the competence of the caprock as a tight barrier capable of ensuring long-term confinement. Simulations demonstrate that under all operational scenarios, including injection rate of 1 Mt/yr and variations in well configuration, the system operates strictly within the elastic domain, exhibiting millimetre-scale deformations and stress states consistently remote from the Mohr-Coulomb failure envelope. The Safety Factor remains consistently above rupture level for both the Cacém Formation and the Aveiro Group throughout the simulations. The primary caprock (Cacém Formation) shows only a very minor initial decrease during early injection before stabilising, while the secondary caprock (Aveiro Group) remains essentially constant. This indicates that injection-induced stresses do not threaten mechanical stability and that both sealing units maintain robust mechanical integrity over time.

Containment failure due to caprock breach remains unlikely. All numerical simulations show caprock maintaining integrity (no CO<sub>2</sub> reaching above primary seal) and, therefore, containment failure risk is considered low.

#### 4.1.3.4 Risks evaluation and recommendations

The likelihood of caprock failure, even at commercial scale, is low due to the favourable initial stress state and because the perforation intervals for CO<sub>2</sub> injection are defined at the deepest part of the reservoir, several dozen meters below the caprock. However, the analysis is constrained by the assumption of initial reservoir pressure, bringing uncertainty to the analysis and leading to a **Significant** classification.

Risk scenario	Key findings	Risk evaluation
<b>Containment failure</b>	Geomechanical model demonstrated that the caprock integrity is never breached during the 30 years injection period, even if the injection rate is expanded up to 1 Mt/yr, but if it occurred impact would result from social acceptance issues. However, the lack of data about initial pressure conditions is an important constrain to the analysis	Significant

Pressure management is paramount to keep this low risk, so it is recommended that:

- **Monitoring bottomhole pressure:** monitoring efforts during the injection and early post-injection phases should focus on pressure evolution and integrity verification.
- **Redo risk assessment following the Pilot Phase:** maintain periodic reviews of geomechanical models as additional field data become available;
- **Operational control:** Operational planning should avoid sudden, large increases in injection pressure, and any future expansion of the injection should be preceded by a site-specific reassessment of caprock stress conditions.

#### 4.1.4 Chemical interaction of CO<sub>2</sub> with seal

The risk of CO<sub>2</sub> leakage due to geochemical interactions between CO<sub>2</sub> and caprock at the reservoir-caprock interface is critical in CO<sub>2</sub> storage operations and must be carefully assessed over the long-term post-injection period (1000-years). Dissolved CO<sub>2</sub> acidifies the brine and in contact with the carbonated phase of caprock may create chemical disequilibrium, particularly through the dissolution of mineral components and a localised increase in porosity and permeability. This can lead to the generation of potential leakage pathways through the caprock. If this occurs, it may pose a critical threat to caprock integrity and the safe long-term containment of CO<sub>2</sub> in the reservoir.

This risk was evaluated through numerical modelling in WP3 and the approach and results are described in detail in Deliverable D3.5 (Pereira et al., 2026b). The following presents a summary of the work conducted.

##### 4.1.4.1 Key data and assumptions

The caprock is represented as a thick, multi-lithofacies formation composed primarily of carbonate-dominated units with interbedded marl and shale-rich layers (see section 2.3). A key feature of the system is the presence of a low-permeability shale layer at the reservoir-caprock interface, identified at the legacy well Do-1C, the nearest one to the CO<sub>2</sub> injection site.

Petrophysical properties assigned to the caprock reflect conservative values reported in the literature for shale and marl formations, with very low vertical permeability and low-to-moderate porosity (from the bottom towards to the top of the caprock). In the reference case, the shale layer is assumed to be laterally continuous and acts as the primary sealing barrier. Mineralogical composition includes clay minerals, carbonates, and minor silicates, allowing for buffering reactions in response to CO<sub>2</sub>-rich brine (Table 7). Uncertainty in mineral volume fractions is explicitly considered through sensitivity scenarios, while porosity and permeability are initially assumed to remain constant unless altered by geochemical reactions.

*Table 7: Caprock mineral composition for the reference case scenario.*

Samples (wt%)	Lithofacies	Quartz	Feld-K	Calcite	Dolomite	Kaolinite
<b>Upper member</b>	Limestone	7	2	79	10	2
<b>Lower member</b>	Marl	15	3	32	5	45
	Dolomite	5	1	15	75	4
	Shale	25	5	5	2	63

Fluid properties and thermodynamic conditions correspond to deep saline aquifer storage, with CO<sub>2</sub> in a supercritical state. The simulations assume fully saturated conditions within the caprock, no pre-existing fractures, and no mechanically induced damage during injection. Chemical equilibrium is assumed between formation water and caprock minerals, with disequilibrium induced only by the upward diffusion or migration of dissolved CO<sub>2</sub>. These assumptions are intentionally conservative and designed to test caprock performance under both realistic and pessimistic conditions.

##### 4.1.4.2 Modelling approach

Caprock integrity was evaluated using a fully coupled reactive transport modelling framework that accounts for multiphase flow, geochemical reactions, non-isothermal (complex Thermo-Hydro-Chemical – THC - simulation), and porosity-permeability evolution. The modelling domain focused on the reservoir-caprock system in the vicinity of the injection well, particularly the top layers of the reservoir to represent the interface with the caprock, allowing detailed analysis of vertical CO<sub>2</sub> migration, dissolution processes, and geochemical alteration at the interface.

A reference case scenario was first established, representing the best-estimate geological configuration, including the intact shale layer at the bottom of the caprock (Table 7). Two sensitivity scenarios were then defined to evaluate the impact of mineralogical uncertainty within the caprock, by varying the volume fractions of carbonate and clay minerals while keeping petrophysical properties of the different lithofacies unchanged. These scenarios aim to capture uncertainty in reaction kinetics and buffering capacity rather than structural sealing efficiency.

Finally, a deliberately conservative worst-case scenario was simulated, in which the petrophysical properties of the basal caprock unit were significantly increased to represent a predominantly marl-carbonated facies or the partial absence (lateral discontinuity) of the shale layer. This scenario tests the sensitivity of caprock integrity to enhanced permeability pathways and reduced sealing efficiency.

All scenarios were simulated over the injection period, to represent the simulation scenario of a previous CO<sub>2</sub> migration towards the caprock (D3.4, Pereira et al., 2026a), followed by a long-term post-injection phase extending to 1000 years. Model outputs include gas and aqueous CO<sub>2</sub> distribution, pH evolution, mineral dissolution and precipitation, and porosity changes. Particular attention was given to the extent of CO<sub>2</sub> penetration into the caprock and the spatial distribution of geochemical alterations.

#### 4.1.4.3 Results

Figure 36 illustrates the extent of CO<sub>2</sub> migration within the aquifer–caprock system for the reference case after 1000 years post-injection periods. The CO<sub>2</sub> plume remains vertically constrained at the bottom of the caprock, with no observable penetration into the overlying lithofacies of the sealing formation. This behaviour highlights the dominant control exerted by the low-permeability shale layer at the reservoir–caprock interface, which effectively prevents upward migration of free-phase CO<sub>2</sub> despite prolonged exposure to elevated CO<sub>2</sub> partial pressures.

Carbonate minerals (calcite and dolomite) undergo dissolution during injection due to CO<sub>2</sub>-induced acidification, followed by partial re-equilibration during the post-injection phase. Porosity changes are minor (on the order of 10<sup>-3</sup> or less), and do not impact the sealing capacity of the caprock.

The sensitivity analysis shows results that are nearly indistinguishable from the reference case. In contrast, the **worst-case scenario** – characterized by increased porosity and permeability of the shale layer – exhibits limited upward CO<sub>2</sub> migration into the lower part of the caprock, although CO<sub>2</sub> penetration is restricted to a few meters above the reservoir–caprock interface. Over 1000 years of post-injection evolution, localized zones show full penetration of the bottom shale layer, with gas saturation reaching values up to 0.2. Despite this localized breach, CO<sub>2</sub> does not propagate into overlying geological units due to the substantial overall thickness of the caprock. Dissolved CO<sub>2</sub> concentrations and acidification are confined to the bottom of the caprock, and porosity changes remain minimal.

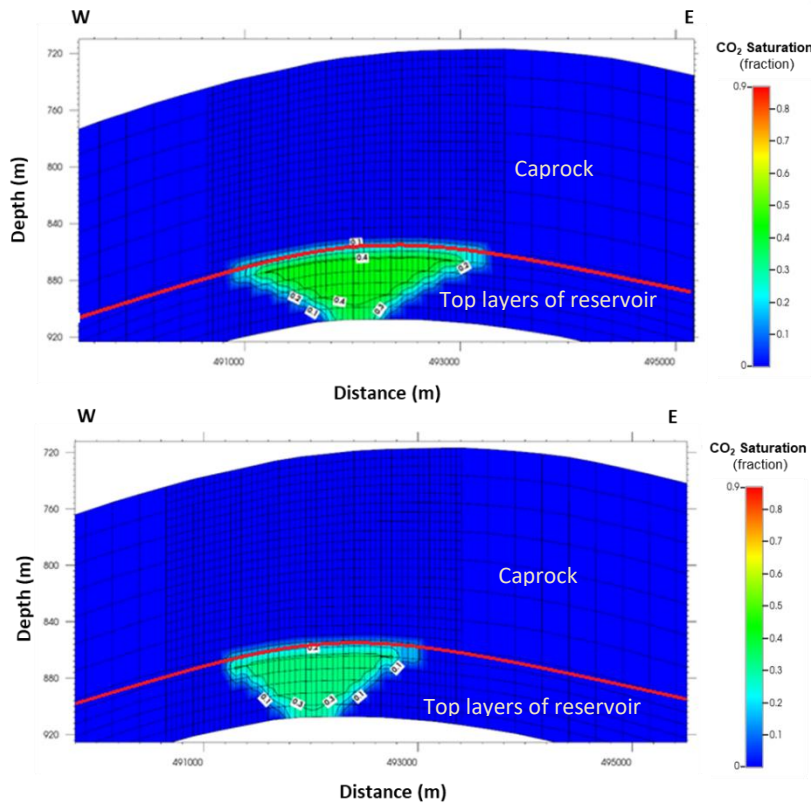


Figure 36: Vertical sections of the spatial distribution of CO<sub>2</sub> saturation in the aquifer and caprock after 10 years of CO<sub>2</sub> injection (initial state) (top) and 1000 years of post-injection period (bottom). The red line illustrates the interface between the reservoir and the caprock.

Overall, the results demonstrate that, under realistic reference case and sensitivity conditions, the caprock maintains its sealing function over long timescales. Even under pessimistic assumptions regarding caprock petrophysical properties, CO<sub>2</sub> migration in the caprock remains limited over time.

#### 4.1.4.4 Risks evaluation and recommendations

**Likelihood** of occurrence of geochemical interaction is **high**. However, the simulation results indicate, for the most realistic scenarios, a **low impact** of CO<sub>2</sub> penetrating the caprock in the reference scenario. Only the worst-case scenario—where caprock petrophysical properties were increased—showed limited CO<sub>2</sub> penetration of a few meters. Given the thickness of the caprock (>50 m), upward leakage into overlying formations is not likely. Nevertheless, there is considerable uncertainty in the caprock petrophysical properties, mineralogical composition, and lateral continuity of its most impermeable lithofacies (notably the shale layer), since it is based in information from a single well (Do-1C). Thus, a conservative approach indicates that **Impact is very low** for the pilot phase and **medium** for the commercial phase, with the overall risk being assessed as **low**. Where caprock petrophysical properties were increased for worst case scenario, modelling showed limited CO<sub>2</sub> penetration of a few meters.

Risk scenario	Key findings	Conclusion
<b>Chemical interaction of CO<sub>2</sub> with seal</b>	While localized CO <sub>2</sub> migration within the caprock may occur, it is unlikely for the CO <sub>2</sub> to fully penetrate the caprock and create leakage pathways to shallower layers.	Not significant

The following recommendations are made:

- **Refine geological model of the caprock:** utilise geological data from the pilot injection well to be integrated with additional 3D seismic data and core analysis to better constrain the mineralogical composition, facies variation and lateral continuity of the lower part of the caprock;
- **Monitoring plan:** the MMV plan should consider the detection of any early traces of geochemical alteration or pressure change responses at the reservoir-caprock interface. Contingency plans should also be developed to address potential localized containment issues.

#### 4.1.5 Leakage due to natural seismicity

Section 3.3.3 clarified that the storage site lies within the 2<sup>nd</sup> lowest seismicity risk zones of EC8. Nonetheless, a probabilistic analysis of natural seismic hazard is necessary to understand the likelihood of natural seismic events of a certain magnitude occurring over the commercial phase project. This section presents a summarised version of the probabilistic analysis. Appendix 3 includes a detailed report.

##### 4.1.5.1 Key data and assumptions

A combined dataset was constructed from the IPMA regional earthquake catalogue (1970–2024) and the one-year PilotSTRATEGY seismic monitoring network implemented in 2023 in *Serra da Boa Viagem*.

The IPMA seismic catalogue comprises 54 years of records, number of events and their magnitude, the Gutenberg-Richter parameters and the variation of the Gutenberg-Richter *b*-value over time. The regional catalogue contains approximately 150 events within a large 100km x 100km area centred around the storage site. The maximum recorded magnitude at regional scale was  $M_L=4$ . Yet only five natural earthquakes have been recorded within a 400 km<sup>2</sup> area surrounding the storage location over the past 54 years, proving that it lies in a tectonically stable domain (Figure 37).

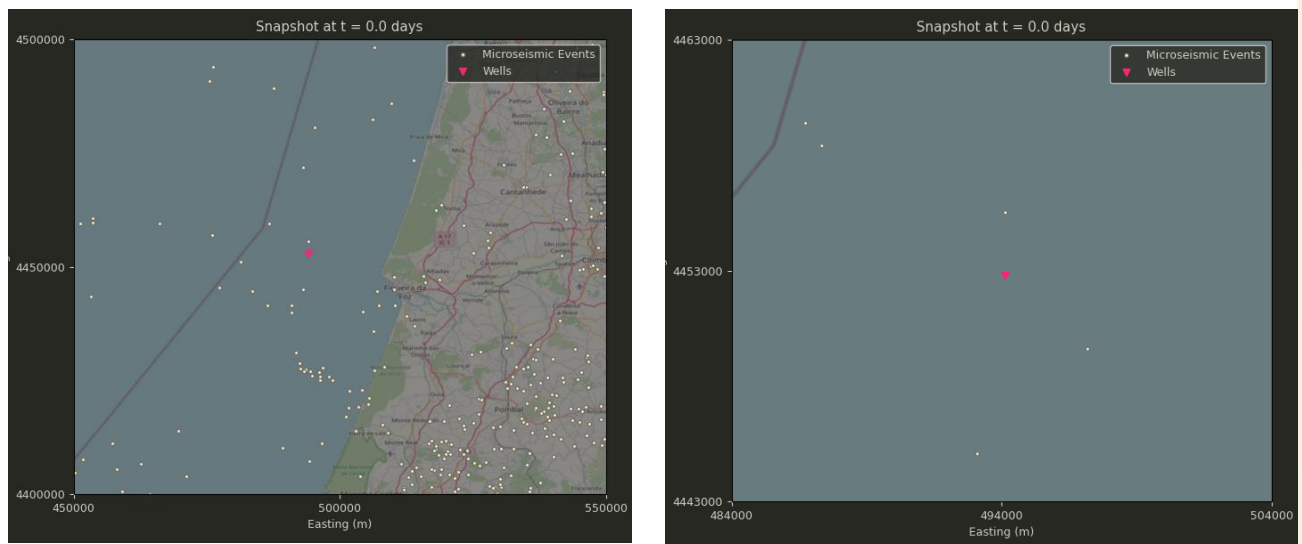


Figure 37: left- Location of the injection well (red triangle) and of the seismic events at: right- regional scale (100 000 km<sup>2</sup>); left - local scale (400 km<sup>2</sup>). See Appendix 3 for high resolution images.

The seismic data collected in the PilotSTRATEGY network from January 2023 to December 2023 corresponds to 154 seismic events, the vast majority very distant from the prospect and generally of very low magnitude ( $M<1$ ).

#### 4.1.5.2 Modelling approach

The ORION toolkit (Kroll et al. 2024a, b) was used to carry out an analysis of the natural seismicity and seismic hazard in the region around the prospect site. ORION is an open-source toolkit to support decision making on seismic hazard analysis and risk management for geologic carbon sequestration. The probabilistic analysis was carried out at regional and local scale for a better understanding of the risk of natural seismic events nearby the injection well, and the probability of those events to exceed a certain magnitude over a given period - 100 years.

We focused on the Seismogenic Index forecast model and used both the IPMA and PilotSTRATEGY catalogues. The Seismogenic Index Model is defined in ORION considering the coefficient of friction, typically assumed 0.4 for sandstone reservoirs, and the tectonic shear and normal stressing rates. The tectonic loading rate in mainland Portugal is very low, ranging between 0.05 to 5 MPa/10000 years. Therefore, a value of 0.5 kPa/yr was used for the tectonic shear and normal stressing rates.

#### 4.1.5.3 Results

The results suggest that, at a regional scale (10000 km<sup>2</sup>), the probability of occurrence of natural events with magnitudes greater than 2.0 and 3.0 (the most common recorded earthquakes in the region), is certain within the next 100 years. When the analysis is restricted to the local scale (400 km<sup>2</sup>), probabilities decrease sharply, being:

- Earthquakes of  $M \geq 2.0$ : less than 80 % chance in 100 years
- Earthquakes of  $M \geq 3.0$ : less than 20 % chance in 100 years
- Earthquakes of  $M \geq 4.0$ : less than < 5 % chance in 100 years
- Earthquakes of  $M \geq 5.0$ : effectively 0 %

These results confirm that moderate natural earthquakes capable of generating significant dynamic stress are unlikely near the storage complex during the pilot phase (3 years) and even during injection in the commercial phase (30 years). The likelihood of an earthquake of  $M \geq 4.0$  occurring during the 3-year pilot is <0.15%, and even over 30 years it is <1.5%. Moreover, any such event's impact on the reservoir/seal is expected to be minor given the distance and depth.

#### 4.1.5.4 Risk evaluation and recommendation

The probabilistic analysis confirms that natural seismicity poses no credible threat to caprock integrity, well stability, or storage containment under normal conditions. For the pilot, the risk is Not significant; for the commercial phase, while large regional quakes can occur, their impact at the site would be minimal, and this risk is effectively managed.

Risk scenario	Key findings	Conclusion
<b>Leakage due to seismicity</b>	The likelihood of earthquakes $M \geq 4$ occurring in the pilot phase is less than 0.15% and in the commercial phase is less than 1.5% during the injection phase, but certain to occur post-closure. A moderate impact of such events, either due to interruption of the injection or leakage through the operation well could result.	Not significant

The analysis confirms that existing natural seismicity poses a Not significant risk under normal storage system evolution. Overall, the existing IPMA network is enough for monitoring requirements. However, the following is recommended:

- **Link between earthquakes and fault F5:** the seismic network implemented in PilotSTRATEGY detected a  $M=3$  earthquake in the vicinity of fault F5, 11 km to the west of the injection well.

It is recommended that the PilotSTRATEGY seismic network at *Serra da Boa Viagem* is maintained through the Pilot and supplemented by ocean bottom nodes (OBN) to clarify if it is an active fault.

#### 4.1.6 Induced seismicity

Experience from similar CO<sub>2</sub> injection projects worldwide suggests felt induced seismicity is rare when injection pressures are kept below fracture pressure, as designed in PilotSTRATEGY. Still, the preliminary assessment in section 3.3.3.2 advised on conducting detailed risk analysis for induced seismicity, both for the pilot and for the commercial phases. In this assessment we followed a dual approach:

- **Probabilistic slip tendency analysis**, based on the Mohr-Coulomb criteria, focusing on: i) assessing the probability that faults identified to the east and west of the prospect may reactivate; and ii) performing a similar analysis for undetected faults that may occur near the injection well. This analysis is reported in detail in Appendix 3, with the main features described in this section;
- **Fault reactivation modelling**, using a geomechanical numerical models and focused once again on the two sets of faults detected in the seismic surveys. The main features and results of this analysis are described below, but Deliverable D3.5 (Pereira et al., 2026) has a detailed description.

##### 4.1.6.1 Probabilistic slip tendency analysis

###### 4.1.6.1.1 Key data and assumptions

A probabilistic analysis of the slip tendency of pre-existing and hypothetical undetected faults is performed to understand if the pressure increase will activate those structures and cause injection-induced seismicity. The *in-situ* stress conditions are fundamental for assessing induced seismicity risk. Based on Ribeiro et al. (1996), this study adopts a maximum horizontal stress azimuth of 145° for Portugal and the adjacent Atlantic region. Assuming an orthogonal stress field, the minimum horizontal stress was assigned an azimuth of 235°, and the vertical stress was considered purely vertical. Both horizontal stresses were assumed to have a plunge of 0°.

No reliable values for the magnitudes of the principal stresses were found in the literature, so approximate estimates based on stakeholder input were used. The site is believed to lie within a normal faulting regime, and the corresponding principal stress magnitudes were defined as.

$$\begin{cases} S_V = 25 \text{ MPa/km} \\ S_{H_{\max}} = S_V = 25 \text{ MPa/km} \\ S_{h_{\min}} = 0.8S_V = 20 \text{ MPa/km} \end{cases} \quad (1)$$

The initial reservoir pore pressure is assumed hydrostatic, ranging from 5.6 to 14.5 MPa, with an average of 9.8 MPa across the reservoir. A radial flow model was applied using a transmissive thickness of 50 m—equal to the injection well’s open-hole section—to provide a conservative estimate, even though the reservoir is thicker. The calculations were performed for a reference depth of 1250 m (well’s open hole section). For an injection rate of 15 kg/s (~0.5 Mt/yr) over 30 years, the model predicts a maximum pressure increase of about 150 psi (≈1 MPa) at the injection point.

The East and West fault zones (see Figure 21 for location) were conceptualised as shown in Figure 38.

Furthermore, hypothetical fractures that may exist but were not detected from the seismic survey have also been considered. Analysis of the fracture network from the seismic sections nearby the prospect site suggests two main families of fractures: NNE-SSW and ESE-WNW (Barata, 2024). The strikes were therefore estimated to range between  $12\text{-}17^\circ$  and  $106\text{-}108^\circ$  with dips ranging  $85\text{-}90^\circ$  for the first fracture set and  $75\text{-}90^\circ$  for the second set (Barata, 2024). Considering these results, a total of 50 random fractures were generated within a reservoir grid of  $8\times 8$  km (Figure 38).

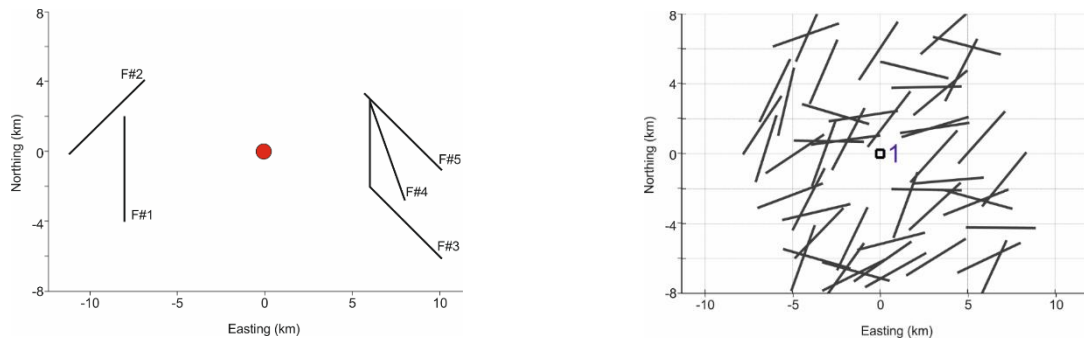


Figure 38- Left) Simplified geological conceptual model used in FSP for the slip tendency analysis. The red dot indicates the injection well; right) Map of hypothetical fractures randomly generated at the location of the injection well.

#### 4.1.6.1.2 Modelling approach

The probabilistic analysis of the slip tendency and activation potential was carried out with the software FSP (CISR, 2023). The tool combines Mohr-Coulomb analysis with semi-analytic pore pressure modelling.

An impact assessment was performed based on linear seismic source models (i.e., faults) and areal sources (i.e., homogeneous distribution of the seismic sources in concentric rings) and is complemented by a ground motion prediction equation adapted to the national territory. Additionally, site conditions are accounted for using a geologically based  $VS_{30}$  model developed specifically for mainland Portugal (Vilanova et al., 2018). The main objective of this analysis is to calculate the peak ground acceleration with a 10% probability of exceedance over a 30-year horizon.

#### 4.1.6.1.3 Results

Using the Mohr–Coulomb criteria, the estimated in-situ stress field, and a friction coefficient of 0.4 (typical for sandstone reservoirs), most pre-existing faults in the study area are favourably oriented for slip but not at a critical state of stress. These faults could be reactivated if pore pressure increases by  $7.2\text{--}16.3$  MPa ( $1048\text{--}2357$  psi), much higher than the estimated pressure increase of 1 MPa.

Overall, the slip-tendency and reactivation assessments indicate a **low** likelihood of fault activation at the planned injection conditions. Probabilistic slip-tendency analysis shows that quasi-optimally oriented faults have a 17% slip probability under the modelled pressure increase of  $\sim 30$  psi imposed at the location of the faults indicating that pore pressure near these structures should remain below this threshold for safe  $\text{CO}_2$  storage (Figure 39).

As for potential fractures undetected by the seismic surveys, these fractures are not critically stressed, though quasi-optimally oriented fractures may slip if pore pressure increases by more than 6.9 MPa at 1250 m depth (Figure 39). The probability of slip for these fractures at the forecasted maximum pressure increase of 1 MPa (150 psi) is approximately 20% (Figure 39). Since the pressure front decays with distance from the injection well, slip probability decreases for structures located further away.

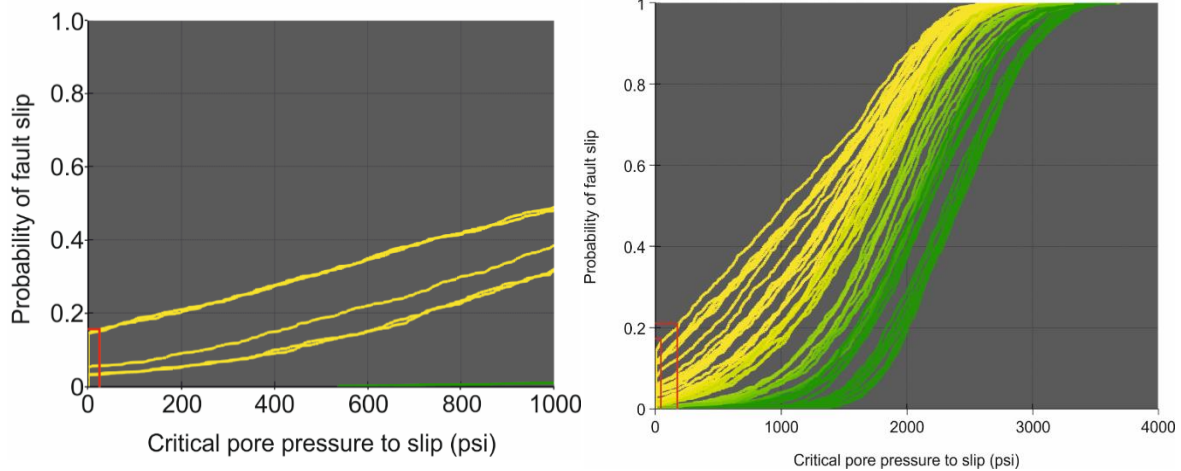


Figure 39 - Cumulative probability function of slip as a function of pore pressure increase for: left) on each detected fault; right) of each randomly generated fracture in the fracture network.

As for Impact and the probabilistic seismic hazard, the resulting Peak Ground Acceleration varies between 0.013-0.021 g, and Modified Mercalli Intensities (MMI) between 2.4–3.3 in the populated areas nearest the offshore injection point (Figure 40), with 10% probability of exceedance over a 30-year horizon. These values correspond to “Very Weak” shaking on the MMI scale, typically not felt by people and no damage imposed to structures.

**PSHA INT (MMI) 30 years, 10%**

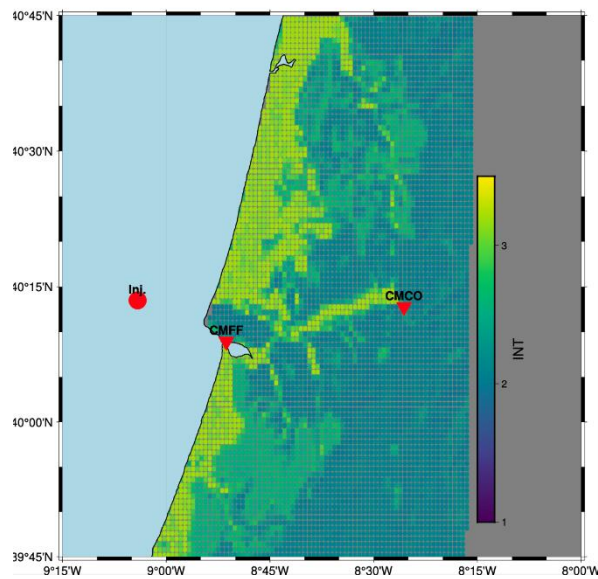


Figure 40 - Intensities (MMI) values with 10% probability of exceedance in 30 years. Inj- Injection site, CMFF (Figueira da Foz City Council) CMCO (Coimbra City Council).

**4.1.6.2 Fault Reactivation modelling**

**4.1.6.2.1 Key data and assumptions**

In the scope of WP3, a detailed hydromechanical model was implemented in FLAC3D to evaluate how evolving pressures during the 30-year injection period may influence the effective stress state along faults F2 and F5, i.e., the faults located in the east and west, respectively, at the prospect Q4-TV1. The hydromechanical model reproduces the structural geometry, lithological layering, and fault architecture used in the reservoir flow model (Figure 41).

The initial state and boundary conditions are chosen in accordance with the Lusitanian Basin slight extensive regime, with a major horizontal stress direction of N145° (Heidbach *et al*, 2025). The initial state is obtained by applying gravity and setting the horizontal stress as  $\sigma_{Hmax} = \sigma_V$  and  $\sigma_{hmin} = 0.8 \times \sigma_V$  on all four model sides, hence leading to a slightly extensive regime. Bottom boundary has fixed normal displacements, and top boundary is free. The initial pore pressure is hydrostatic.

The elastic parameters are based on the static model in D3.2 (Chassagne, 2024). No data is available for the plastic parameters in the faults. Standard parameters were used: cohesion  $c=10$  MPa; friction angle  $\phi=30^\circ$ .

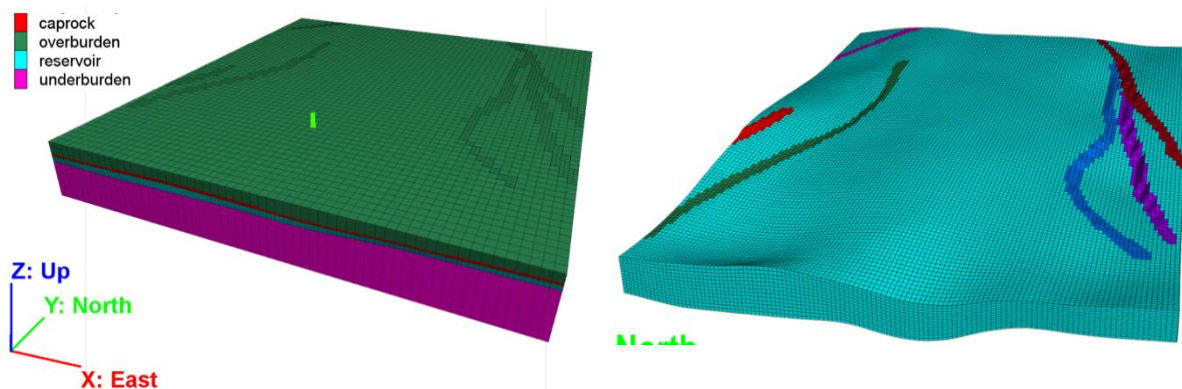


Figure 41 - Geological considerations of the mechanical model: rock layers integrated (left) and fault's locations (right, view in the reservoir layer).

#### 4.1.6.2.2 Modelling approach

FLAC3D enables three-dimensional simulation of stress redistribution, deformation, and potential failure mechanisms induced by increased pore pressure associated with CO<sub>2</sub> injection into deep geological formations. It allows assessment of reservoir integrity, caprock stability, and fault reactivation risks under various injection scenarios. The modelling results provide valuable insight into the safe design of injection pressures and rates of CO<sub>2</sub> storage projects, three-dimensional simulation of stress redistribution, deformation, and potential failure mechanisms induced by increased pore pressure associated with CO<sub>2</sub> injection into deep geological formations.

The FLAC3D model simulated the mechanical response of faults over multiple injection time steps (1, 4, 8, 10, 16, 20, and 30 years). For each time step, the effective stress state in fault cells was plotted on Mohr diagrams to determine whether stress paths approached the failure threshold.

#### 4.1.6.2.3 Results

Across all simulations, faults remained well within the stable domain of the Mohr–Coulomb failure envelope. Even after 30 years of continuous injection, no fault cells exhibited stress conditions close to shear failure. Geomechanical simulations using the calibrated model show that injection at the planned pressure ( $\leq 165$  bar) does not induce shear slip on any faults – all stress states remain well within stable limits (Figure 42d shows the Mohr circles far from failure envelope). No scenarios predicted any seismic events that would be felt.

The Mohr–Coulomb relation was applied to compute the extra overpressure needed at each fault cell to trigger fault slip. For the reference scenario, this additional overpressure exceeds 180 bar, far beyond any pressure permissible during CO<sub>2</sub> injection. **These results indicate extremely large safety**

margins relative to fault failure thresholds and demonstrate that fault reactivation is mechanically implausible under the planned injection strategy.

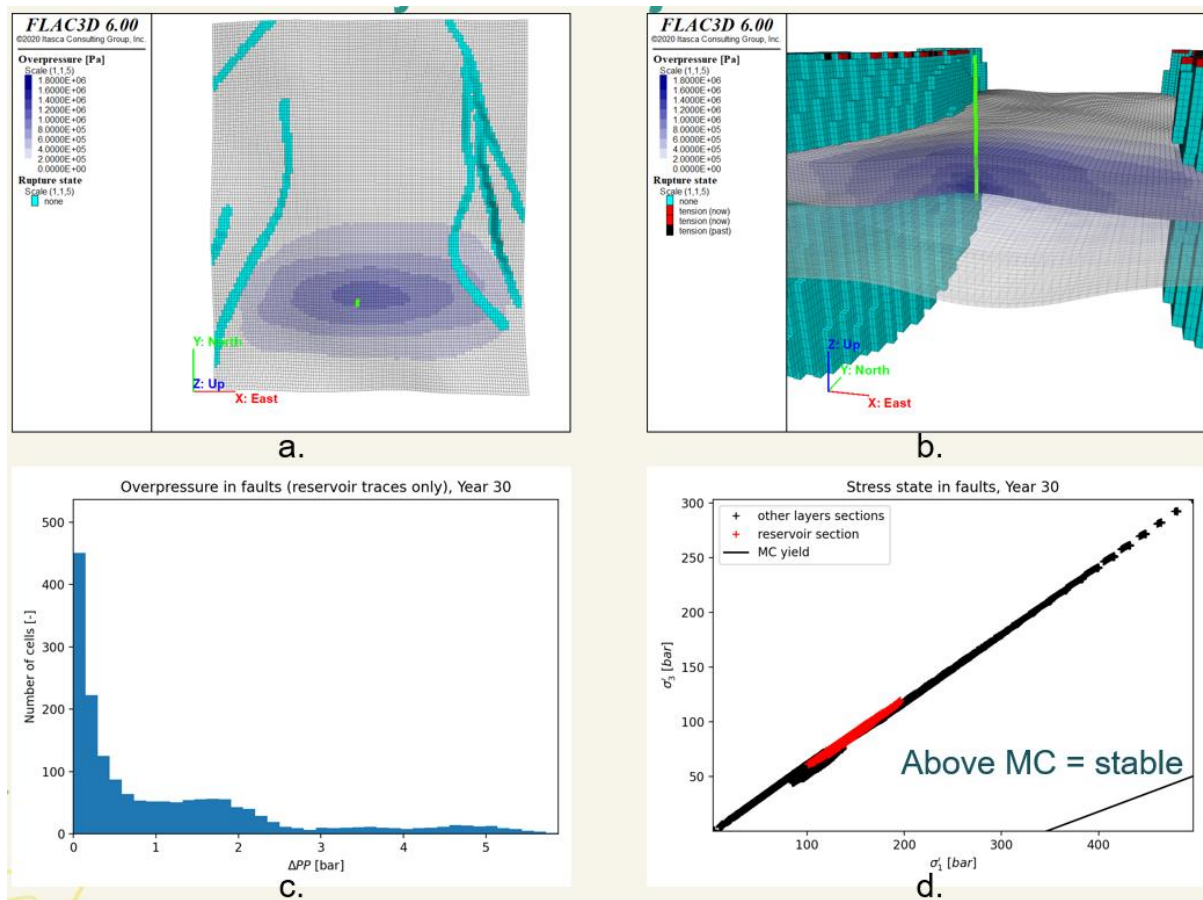


Figure 42: Fault reactivation assessment results after 30 years of injection. (a) FLAC3D top-view showing reservoir overpressure distribution and fault traces, indicating low perturbation near fault planes; (b) East-west cross-section illustrating vertical distribution of overpressure and fault geometry, with no rupture conditions observed; (c) Histogram of overpressure within fault cells intersecting the reservoir, showing values generally below 2 bar; (d) Effective stress state of fault points plotted against the Mohr-Coulomb yield envelope, demonstrating that all points remain in the stable region with significant safety margins.

#### 4.1.6.3 Risk evaluation and recommendations

The two methodologies applied confirmed that induced seismicity does not present a credible risk to containment, well integrity, or operational safety under the planned injection scenario. Essentially, the analyses indicate induced seismic risk is very low, but careful pressure management and monitoring should, nonetheless, be implemented to ensure any microseismic activity remains below harmful thresholds.

Risk scenario	Key findings	Conclusion
<b>Induced Seismicity</b>	Slip tendency analysis and mechanical numerical modelling confirmed that the risk of fault reactivation is Low to very Low and that its impact is Low since any induced seismicity would be below the threshold for being felt by population and much lower than the natural seismicity of the region.	Not significant

Despite the very Low risk, and given the social acceptance relevance of seismicity risks, the following recommendations are made:

- **Implement a Microseismic Monitoring Baseline and Plan.** Prior to injection, establish a sensitive monitoring network to characterize the background seismicity of the site and to detect and locate any microseismic activity during operations, thereby verifying model predictions and ensuring early awareness.
- **Implement a Traffic Light System decision tool:** a decision-making approach to mitigate the risk of potential seismic events induced by CO<sub>2</sub> injection should be implemented based on the traffic light system described in Appendix 3.

#### 4.1.7 Injectivity loss

Injectivity loss refers to a progressive reduction in well deliverability during operations, typically caused by near-wellbore phenomena such as mineral precipitation, salt crystallisation, fines migration, or pore throat blockage. Unmanaged injectivity loss may limit the capacity to sustain planned injection rates or require temporary shutdowns for remedial actions.

Section 3.3.5.2, relying on the laboratory experiments and modelling with PHREEQC, demonstrated that CO<sub>2</sub>-rock-brine interaction in the siliciclastic reservoir does not pose a risk for loss of injectivity due to mineral precipitation. However, injectivity loss can result from the potential precipitation of salt (halite) during CO<sub>2</sub> injection. This risk was evaluated through numerical modelling in WP3 and the approach and results are described in detail in Deliverable D3.5 (Pereira et al. 2026b). Below is presented a summary of the work conducted.

##### 4.1.7.1 Key data and assumptions

Dynamic simulations to assess potential injectivity loss were conducted based on thermal-hydraulic-chemical (THC) data. Key data included reservoir properties such as permeability, porosity, relative permeability and capillary entry pressure curves, as well as thermal conductivity and heat capacity for the reservoir rock. All data sets were based on those defined in the static and dynamic model described in D3.2 (Bouquet, 2024).

The reference case scenario was established, along with an uncertainty analysis that examined several key parameters: reservoir salinity, injection bottomhole temperature and injection rate. The reference case scenario targeted an injection rate of approximately 15 Mt over the 30-year period. The bottomhole CO<sub>2</sub> temperature was set at 26°C, and the reservoir salinity was set at 56 g/L. For the uncertainty analysis, the following variations were considered and compared with the reference case:

- An increased injection rate to 1 Mt/yr;
- Variations in reservoir salinity (10 g/L and 130 g/L);
- Variations in CO<sub>2</sub> injection temperature (20°C and 40°C);
- A worst-case scenario combining the higher injection rate (1 Mt/yr) with the highest salinity (130 g/L).

##### 4.1.7.2 Modelling approach

A 2D radial model was used to represent the lower 50 m of the reservoir while preserving the original depth, pressure, and temperature conditions. Petrophysical properties were aligned with previous static and dynamic modelling, with minor adjustments required when converting the 10 m thick Cartesian layers to a radial grid with 1 m vertical resolution. The model was simplified into five

homogeneous layers, maintaining vertical heterogeneity, while assuming lateral homogeneity within each reservoir layer. A larger radial extent was included to ensure realistic reservoir pressure behaviour during injection. Chemical parameters accounted for halite precipitation using the Wolery thermodynamic database.-

The potential for injectivity loss was evaluated in terms of halite precipitation, reservoir porosity changes and the injectivity index. The evolution of the cumulative CO<sub>2</sub> injection rate was also presented and compared across the different simulation scenarios to identify potential losses.

#### 4.1.7.3 Results

The results from the reference case scenario show that after 30 years of injection, halite precipitation extends up to 40m from the injection well (Figure 43) resulting in porosity changes and higher CO<sub>2</sub> residual resistance factors. Despite these phenomenological impacts in the near-wellbore zone, the cumulative CO<sub>2</sub> injection rate does not suffer major disruption, reaching the expected amount of approximately 15 Mt – the same as without halite precipitation. These results suggest that reservoir injectivity remains intact over time.

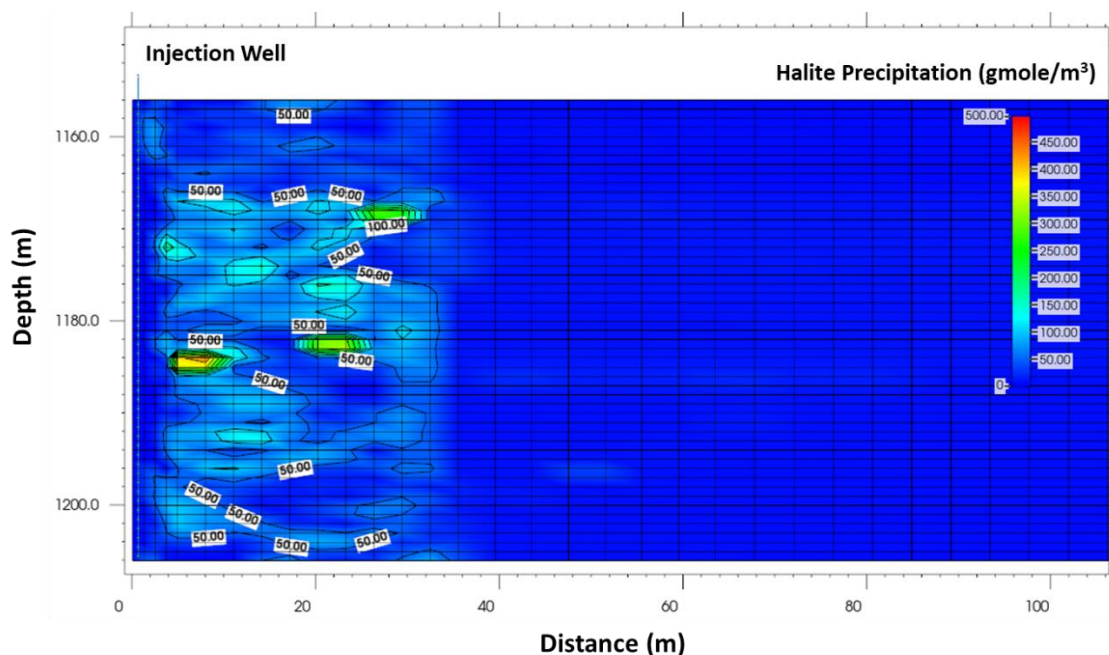


Figure 43: Vertical section of the reservoir illustrating the salt (halite precipitation) close to the wellbore of the injection well for the reference case scenario.

Uncertainty analysis shows that reservoir salinity, injection rate, and injection temperature influence halite precipitation differently. Higher salinity significantly increased the amount of halite precipitation, although the spatial extent did not differ markedly from the reference case. A similar impact was seen for higher injection rates, with the area affected by porosity changes and halite precipitation extending to about 50 m from the injection well, particularly in the lower part of the reservoir. Still, no major impact on injectivity integrity was observed. CO<sub>2</sub> bottomhole temperature had minimal impact on total halite precipitation but it alters the spatial distribution of porosity changes and local precipitation.

Only the worst-case scenario – combining the highest reservoir salinity with a higher injection rate – resulted in localized injectivity losses. However, for the reference case injection rate, even when combined with higher salinity, these localized injectivity issues did not occur. This suggests that even

if some injectivity loss is observed over time, controlling bottom-hole pressure through temporary reductions in the instantaneous injection rate may overcome potential injection rate issues.

#### 4.1.7.4 Risks evaluation and recommendations

Based on the simulation results, the risk of injectivity loss is assessed as low, because although the likelihood of halite precipitation is moderate-to-high, its impact on injectivity loss is negligible. Even though halite forms near the wellbore over 30 years, it does not hinder achieving the CO<sub>2</sub> storage target of ~15 Mt. A low-to-moderate risk is only foreseen in a worst-case scenario of significantly elevated reservoir salinity and increased injection rates, which could lead to localized permeability reduction and a temporary drop in injectivity.

Risk scenario	Key findings	Conclusion
<b>Injectivity loss due to mineral precipitation</b>	Numerical modelling of the injection period, including a geochemical component, demonstrates that the likelihood of salt precipitation is moderate to high, but there is very low to low impact on the injection rate.	Not significant

The following recommendations should be considered:

1. **Monitoring for BHP:** monitoring of bottomhole pressure is essential. If pressure suddenly rises, this may indicate potential plugging due to salt precipitation and, therefore, the instantaneous injection rate should be temporarily reduced, and operational measures should be implemented for removal of salt;
2. **Baseline hydrochemistry.** During well drilling, accurate pre-injection measurement of formation water salinity is recommended to reassess the risk and guide the injection strategy.

## 4.2 Risk analysis synthesis

The findings from preliminary (Round 1) and detailed (Round 2) analyses were integrated in a risk matrix for the Lusitanian Basin CO<sub>2</sub> storage site (Figure 44 and Table 8). The risk matrix combines qualitative **Likelihood** and **Impact** classes for internal risk prioritisation, according to categories in Table 5. In parallel, risks are classified as **Significant** or **Not Significant** following the CCS Directive and Guidance Document 1 (GD1), which focus on containment integrity and environmental protection. Accordingly, the **High** and **Very High** zones of the risk matrix correspond to **Significant** risks requiring mitigation or design adjustment, while lower zones are considered **Not Significant** provided they remain within acceptable limits and are managed through design and monitoring.

It shows that most identified hazards fall in the **Low-risk category** in terms of both probability and impact. In Round 1, some scenarios were flagged for Round 2 due to uncertainties – e.g. potential well leakage, caprock failure under pressure, caprock integrity due to geochemical reactions, or induced seismicity. However, after incorporating site-specific data and advanced modelling in Round 2, most risks in pilot phase **have classified to low or very low levels**, with the exception of the risk of “leakage through operation well” which plots as moderate risk. During the commercial phase there are several hazards that classify as moderate risk, namely: “R3c-Leakage through caprock due to pressure build up” and “R4c-Leakage through caprock due to poor geologic characteristics”, “R9c - Injectivity below expectations” and “R11c – Storage capacity below expectations”.

For instance, fault reactivation and induced seismicity, which were initially a concern, were shown by geomechanical modelling and PSHA to be **Not significant** (negligible slip tendency at expected pressures) and would in any case result in only minor, undetectable seismic events.

The legacy well Do-1C was shown not to pose a risk to the site, since the CO<sub>2</sub> will not reach it. Injectivity loss was examined by coupled modelling (including salt precipitation effects), and it was found that injectivity will remain sufficient over time; only under an extreme combination of high salinity and high injection rate, would localized decrease in porosity result in a reduction in injectivity which can be managed by pressure control. In summary, **no scenario evaluated in either Round 1 or Round 2 indicates an unmanageable or unacceptable risk** to containment, safety, or environmental protection. This comprehensive two-stage risk assessment provides a **high degree of confidence** that the Lusitanian Basin pilot site can be operated safely and in compliance with regulatory standards.

<b>Likelihood</b>	<b>Very High</b>	R8c				
	<b>High</b>	R10c				
	<b>Medium</b>	R9p	R10p R10c			
	<b>Low</b>	R8p	R7c	R3c R4c	R9c	
	<b>Very Low</b>	R2p R5p	R2c R5c R6p R7p	R11p R6c	R1c R3p R4p	R1p R11c
		<b>Very Low</b>	<b>Low</b>	<b>Medium</b>	<b>High</b>	<b>Very High</b>
		<b>Impact</b>				

Figure 44 – Risk matrix. The Risk ID (R#p and R#c) follows Table 8, with “p” and “c” referring to Pilot and Commercial.

Table 8: Updated risk analysis. Likelihood and Impact categories follow Table 5.

Risk ID	Risk Scenario	Phase	Likelihood	Impact	Risk Evaluation*
R1p	Leakage through operation well	Pilot	Very low	Very high	Not significant
R1c	Leakage through operation well	Commercial	Very low	High	Not significant
R2p	Leakage through abandoned well	Pilot	Very low	Very low	Not significant
R2c	Leakage through abandoned well	Commercial	Very low	Low	Not significant
R3p	Leakage through caprock due to pressure build up	Pilot	Very Low	High	Not significant
R3c	Leakage through caprock due to pressure build up	Commercial	Low	Medium	<b>Significant</b>
R4p	Leakage through caprock due to poor geologic characteristics	Pilot	Very low	High	Not significant
R4c	Leakage through caprock due to poor geologic characteristics	Commercial	Low	Medium	<b>Significant</b>

Risk ID	Risk Scenario	Phase	Likelihood	Impact	Risk Evaluation*
R5p	Leakage through faults	Pilot	Very low	Very low	Not significant
R5c	Leakage through faults	Commercial	Very low	Low	Not significant
R6p	Leakage due to natural seismicity	Pilot	Very low	Low	Not significant
R6c	Leakage due to natural seismicity	Commercial	Low	Medium	Not significant
R7p	Induced seismicity	Pilot	Very low	Low	Not significant
R7c	Induced seismicity	Commercial	Low	Low	Not significant
R8p	Chemical interaction of CO <sub>2</sub> with seal	Pilot	Low	Very low	Not significant
R8c	Chemical interaction of CO <sub>2</sub> with seal	Commercial	Very high	Very low	Not significant
R9p	Injectivity below expectations	Pilot	Medium	Very low	Not significant
R9c	Injectivity below expectations	Commercial	Low	High	<b>Significant</b>
R10p	Injectivity loss	Pilot	medium	Low	Not significant
R10c	Injectivity loss	Commercial	High	Low	Not significant
R11p	Storage capacity below expectations	Pilot	Very low	Very low	Not significant
R11c	Storage capacity below expectations	Commercial	Very Low	Very high	<b>Significant</b>

\*Designations follow the CCS Directive Guidance Document 1: **Not significant**: risks that do not call into question the purpose of the CCS Directive for the storage site concerned; **Significant**: risks that must be reduced to Not significant by taking risk-reducing measures.

### 4.3 Analysis of Consequences and Implications for Scalability

This two-round risk assessment concludes that the likelihood of uncontrolled CO<sub>2</sub> leakage or other major safety impacts during the Pilot phase (≤100 kt) is very low, and the updated risk table (Table 8) retains a Not Significant designation across all Pilot hazards. Accordingly, classical “failure consequences” are not the dominant decision driver for the Pilot phase.

For potential scale-up to a Commercial scenario, the dominant consequences are instead linked to performance, uncertainty reduction, and the strength of the evidence base supporting long-term containment. In Table 8, four hazards remain designated Significant for the Commercial case: R3c (caprock integrity under pressure build-up), R4c (caprock uncertainty related to potentially unfavourable geological characteristics), R9c (injectivity below expectations), and R11c (storage capacity below expectations). These designations follow the terminology of the CCS Directive risk-management framework (as reflected in the project’s GD-based designation note), and they function as triggers for targeted risk reduction and evidence gathering rather than as indicators of immediate unsafe conditions.

#### 4.3.1 Dominant Uncertainty: The Impact on the Commercial Performance (pressure, injectivity, and capacity)

In the Commercial scenario, the most decision-relevant “consequence” is the size and robustness of the achievable injection and storage envelope under conservative pressure-management constraints. The key uncertainties that shape this envelope map directly to the four commercial phase Significant hazards:

- i. Pressure and caprock response (R3c): If pressure build-up is higher than expected, conservative pressure limits may constrain injection rates and/or require phased operation, additional wells, or revised injection strategy to maintain a robust containment margin.
- ii. Caprock geological uncertainty (R4c): Uncertainty in caprock continuity/heterogeneity that may constrain operational flexibility until reduced by targeted characterisation and model updates.
- iii. Injectivity below expectations (R9c): Lower injectivity primarily affects feasibility and economics (number of wells, CAPEX/OPEX, and operational flexibility) rather than containment integrity. The Pilot phase is the primary mechanism to calibrate injectivity from measured rate–pressure behaviour and to validate near-wellbore assumptions.
- iv. Capacity below expectations (R11c): Capacity uncertainty affects the commercial development envelope and investment confidence. It requires updated capacity estimates using pilot-derived data, refined geological/dynamic modelling, and consideration of phased development or alternative structures within the storage complex.

#### 4.3.2 Decision Pathway for Project Scaling

The findings can be synthesised into a clear pilot-to-commercial decision pathway:

- 1) Pilot execution and evidence acquisition: execute the Pilot injection programme and collect critical monitoring and characterisation evidence (pressure response, injectivity calibration, plume/pressure behaviour, relevant caprock indicators, and baseline seismicity).
- 2) Model updating and risk re-evaluation: integrate pilot-derived data into the static/dynamic/geomechanical models and re-evaluate Table 8 designations, focusing on Significant hazards (R3c/R4c/R9c/R11c).
- 3) Commercial readiness decision: proceed to commercial deployment only when (i) no hazards fall within the High or Very High zones of the risk matrix (Figure 44), and (ii) the residual Significant hazards are reduced to Not Significant and/or shown to be robustly manageable through proportionate monitoring and corrective measures, consistent with the lifecycle risk management logic used in the project’s GD-based designation approach.

## 5. Recommendations

This chapter consolidates the recommendations derived from the WP5 risk assessment, structured to support decision-making for the pilot phase and any potential transition to commercial phase deployment. The recommendations below are structured to reduce these hazards toward a **Not significant** status prior to a commercial decision.

### 5.1 Future research and data acquisition

**Objective:** *Targeted reduction of key geological and operational uncertainties identified in the risk assessment, particularly those governing pressure response, containment robustness, and scalability.*

#### A) Enhance storage complex characterization

**Action A.1: Acquire high-resolution 3D seismic data covering the full storage complex.**

Risk justification: The current seismic interpretation relies partly on 2D data. Improved 3D imaging will reduce uncertainty regarding fault presence, structural continuity, and depth conversion, decreasing the risk of unexpected leakage paths and reservoir compartmentalisation.

**Action A.2:** Collect comprehensive formation evaluation data during pilot well drilling, including coring and logging of reservoir and caprock intervals.

Risk justification: Key reservoir and caprock properties are currently constrained by legacy data and analogues. Direct measurements from the pilot well will reduce uncertainty in parameters that control injectivity, pressure response, and long-term containment performance.

**Action A.3:** Update the static geological model by integrating newly acquired seismic and well data.

Risk justification: Updated geological models supports robust prediction of plume migration, pressure evolution, and fault stability under both pilot and potential commercial scenarios.

#### B) Derisk caprock and abandoned well integrity

**Action B.1:** Perform laboratory testing on newly acquired core material to refine reservoir and caprock properties.

Risk justification: Laboratory measurements will reduce uncertainty associated with permeability, mechanical strength, and CO<sub>2</sub>-rock-brine interactions. This directly addresses residual uncertainties highlighted in the risk assessment related to injectivity evolution and long-term caprock integrity.

**Action B.2:** Precisely locate and characterise the legacy well Do-1C and establish an environmental baseline around its wellhead.

Risk justification: Although modelling demonstrates that the CO<sub>2</sub> plume will not reach Do-1C, its physical condition remains uncertain. Baseline characterisation and monitoring reduce uncertainty associated with legacy well integrity and strengthen long-term assurance.

## 5.2 Injection design and operational strategies

**Objective:** *Translate risk assessment findings into robust design rules and operational controls ensuring safe injection and adaptive management.*

### C) Pressure management

**Action C1:** Maintain bottom-hole injection pressure within conservative geomechanical limits.

Risk justification: The injection operations should follow the ALARP principle (As Low As Reasonably Practicable) for risk: i.e. keep bottom-hole pressure as low as feasible while still meeting injection targets. This means continuous pressure monitoring and procedures to cut back injection rate if pressure approaches the limit.

### D) Phased Injection strategy

**Action D1:** Incorporate Pilot findings before scaling up.

Risk justification: Use the pilot phase to inform any future larger injection. This effectively means implementing a phased development: the pilot is a required precursor that must demonstrate safe behaviour before ramping up. Regulators and the operators should formally agree on criteria (e.g. “no induced events  $M > 2$  during pilot” or “pressure behaviour matches predictions within X%”) that would trigger a review before scaling.

### E) Well design and integrity

**Action E1:** Design and complete the injection well using materials and barriers suitable for CO<sub>2</sub> service and verify integrity prior to injection.

Risk justification: Robust design and verification reduce the likelihood of well-related leakage. The injection well design should follow best practices and undergo integrity tests to confirm no behind casing leaks. During the pilot, routine integrity monitoring (valve checks, annulus pressure tracking) is recommended. During the pilot, routine integrity monitoring (valve checks, annulus pressure tracking) is recommended.

### F) Operational flexibility

**Action F1:** Preserve operational flexibility to adjust injection rates or stop injection if required.

Risk justification: Operational flexibility enables rapid response to unexpected pressure behaviour, injectivity decline, or monitoring signals, ensuring that emerging risks remain within acceptable bounds. The operational plan should include procedures for periodic wellbore clean-out or solvent’s injection if salt or scale is.

**Action F2:** Plan for contingencies.

Risk justification: A contingency plan for any credible operational issues should be devised. All corrective measures should be in place before injection starts, including decision thresholds for when to execute them. This includes having the ability to rapidly reduce injection rate or shut-in if needed, deploying pressure relief, and criteria for mobilizing a relief well if a serious loss of containment occurs.

### 5.3 Monitoring, measurement, verification, and corrective measures

**Objective:** *Ensure early detection of deviations from expected behaviour and enable timely, proportionate corrective actions.*

#### G) Tier 1 monitoring, primary safety indicators

**Action G1:** Implement continuous downhole monitoring, including Bottom-Hole Pressure (BHP), temperature, flow rate and distributed fibre-optic sensors (Acoustic: DAS/Temperature: DTS)

Risk justification: Continuous well monitoring provides early detection of deviations that could precede injectivity loss or containment issues. This continuous monitoring should be used to refine model predictions (history matching) and to provide early-warning of any injectivity issue.

**Action G2:** Conduct time-lapse seismic surveys to track CO<sub>2</sub> plume migration.

Risk justification: Plume monitoring provides direct verification of containment and validates dynamic model predictions, reducing uncertainty related to long-term plume behaviour. Time-lapse (4D) seismic surveys need to be conducted before and after the pilot injection to monitor plume migration.

**Action G3:** Establish baseline formation water chemistry during drilling and before CO<sub>2</sub> injection and monitor for geochemical changes.

Risk justification: Geochemical monitoring supports early detection of unexpected CO<sub>2</sub> migration or chemical reactions that could affect injectivity or seal integrity. This is especially important to manage halite precipitation risk.

#### H) Tier 2 monitoring, containment verification

**Action H1:** Operate a microseismic monitoring network.

Risk justification: Real-time monitoring and predefined microseismicity thresholds ensure that any seismic response remains controlled and does not escalate into a safety or public-acceptance issue. Results of this monitoring network should be used to implement the Traffic Light System (TLS), with defined magnitude thresholds that trigger operational responses.

**Action H2:** Implement seabed and water-column monitoring around the injection site and the legacy well location.

Risk justification: While leakage is not expected, seabed monitoring provides an added safeguard for offshore operations, especially around the injection wellhead and the legacy well Do1C. Utilisation of fixed sensors to track CO<sub>2</sub> flux, dissolved CO<sub>2</sub>, pH, alkalinity, and temperature, complemented with periodic surveys with remotely operated or underwater autonomous vehicles (ROV/AUV) to scan for visual indicators or biological shifts, are recommended. Occasional water column checks (e.g., vessel-based sampling or Conductivity, Temperature, Depth (CTD) casts with pH sensors) can further confirm stable water quality.

#### K) Continuous risk management

**Action K1:** Regular risk assessment updates and maintain a corrective measures plan.

Risk justification: The risk matrix should be revisited using the collected data during the pilot to refine the risk assessment for the commercial phase. During the pilot, if monitoring data significantly differ from predictions, start an interim risk review. Prepared corrective measures,

aligned with CCS Directive requirements, ensure rapid response to any deviation from expected behaviour, preventing unlikely issues from escalating.

## 5.4 Regulatory and legal considerations

**Objective:** *Translate technical safety assurance into regulatory readiness and permitting clarity.*

### L) Regulatory compliance for upscaling

**Action L1:** Develop the Pilot as R&D but ensure permit compliance.

Risk justification: The Pilot does not require a storage permit, but it still needs certain authorizations (e.g. TUPEM) and compliance with environmental and safety rules. Planning should include early engagement with regulators to confirm the pilot's status and obligations.

**Action L2:** Use pilot outcomes to progressively build the technical basis for a potential storage permit under Decree-Law 60/2012.

Risk justification: Early preparation reduces regulatory uncertainty and prevents delays during scale-up. This includes compiling pilot results into a permit-ready dossier—site characterisation, updated capacity estimates, risk assessment, monitoring plan, and a post-closure plan. -up. This includes compiling pilot results into a permit-ready dossier—site characterisation, updated capacity estimates, risk assessment, monitoring plan, and a post-closure plan.

**Action L3:** Align stakeholder engagement with risk assessment and monitoring results.

Risk justification: Maintain regular engagement with local communities, government agencies, and independent experts throughout the pilot improves social acceptance. Risk assessment results and monitoring data should be made public and transparent and a local stakeholder committee should review progress and address concerns to support social acceptance.

## 6. Conclusions

The WP5 risk and safety performance assessment for the CO<sub>2</sub> storage pilot in the offshore Lusitanian Basin has integrated a wide range of geological, engineering, and modelling analyses to evaluate the site's suitability. This analysis – including both the initial Round 1 screening and the refined Round 2 updates – provides an evidence-based confirmation of the long-term containment behaviour, injectivity performance, and overall risk analysis of the storage site. **The offshore pilot storage site is a technically viable, geologically favourable, and operationally safe site for CO<sub>2</sub> storage at the pilot scale and at a commercial scale.**

The storage formation is well-defined and sealed by continuous stratigraphic boundaries; the overlying caprock is thick and mechanically strong, with very low permeability, and is reinforced by a secondary seal. This multi-layered barrier system ensures very low probability of pathways for leakage of CO<sub>2</sub> out of the storage complex. The reservoir itself has sufficient thickness, porosity, and permeability to accommodate both the pilot injection and much larger volumes (commercial injection) without pressure issues.

The advanced Round 2 simulations have strengthened confidence in containment predictions. While the preliminary models already indicated secure storage for the 30-year injection period, the extended 1000-year stochastic simulations have quantified the long-term plume behaviour under uncertainty. Across all considered cases, the CO<sub>2</sub> plume remained entirely within the intended reservoir compartment, never reaching the bounding faults or the legacy well Do-1C in any of the 1100 scenarios. In the most extreme outlier cases, the plume came within ~800 m of the well Do-1C after many centuries, but even then, the CO<sub>2</sub> saturation at the plume edge was so low (<0.1) that it would be immobile and incapable of causing leakage. These results indicate a consistently low probability of any structural or well-related leakage, even under wide ranges of geological uncertainty. In summary, the long-term modelling confirms that **CO<sub>2</sub> will remain safely trapped in the reservoir for the foreseeable future**, with no credible mechanism for escape.

The risk assessment was prudent, since it examined conservative, worst-case scenarios, for each risk. For example, induced seismicity was evaluated assuming maximum stress and full fault transmissivity, yet the resulting seismic risk remained low (no events above the low magnitudes of natural seismicity). Likewise, even a hypothetical and unlikely strategy of high injection rate in a high salinity reservoir only caused minor near-well effects (salt precipitation) that did not compromise injection goals or containment.

The updated Round 2 retains Significant hazards for the commercial scenario (R3c, R4c, R9c and R11c). These hazards are not expected to translate into uncontrolled leakage under the modelled scenarios, but they represent uncertainties and long-term performance considerations that require continued risk-reduction, monitoring, and evidence from the pilot phase before any commercial-scale decision and permitting. In contrast, the pilot-scale scenario remains Not significant across all hazards in the updated assessment, reflecting the small mass injected and operational flexibility.

The designation of certain commercial-phase hazards as “Significant” reflects the structured application of the explicit decision rule defined in Chapter 3 and does not imply the existence of uncontrolled or unacceptable risks. Rather, it identifies areas requiring continued evidence gathering and risk reduction prior to commercial deployment.

From a regulatory and safety standpoint, the analysis shows that the pilot injection will not pose any significant risk to the environment or human health. The likelihood of any leakage or other adverse event is extremely low, and even in the very unlikely event that something does occur (e.g. a microseismic event or a small leak), the monitoring and contingency plans in place would detect and address it well before it became a problem.

**Overall, the risk assessment concludes that with continued implementation of the recommendations (including additional data gathering, model refinement, robust monitoring, etc.), the Lusitanian Basin CO<sub>2</sub> storage site is well positioned to move forward to the operational pilot phase and even to future commercial-scale development.**

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## Appendix 1 – Risk Register

The table below presents an updated risk register for the offshore CO<sub>2</sub> storage pilot in the Lusitanian Basin, incorporating all 45 identified risk scenarios (grouped into seven categories) from the initial HAZID. Each risk is categorized by type (Performance, Safety, or Stakeholder) and linked to the relevant phase (Pilot and/or Commercial). Risk register considers to status classes: **Active** - risks that are either not fully eliminated or depend on operational conditions and therefore must be tracked throughout the project lifecycle. **Closed** - risks that have been assessed and are considered no longer relevant, either because they are demonstrated to be negligible (or because they are fully mitigated). No further monitoring or mitigation actions are required under current assumptions. Mitigation measures and current status are included for each scenario, consistent with the report's recommendations and conclusions, but the MMV plan and mitigation measures are specifically addressed in Deliverable D4.6 - *Permit Dossier: Operation, logistics and well maintenance plans description, Well permits road map, MMV plan and HSE, emergency response and well containment plans*.

This register is intended to be a living document to be updated as new data are acquired during the Pilot.

Risk ID	Risk Description	Category	Type	Phase	Possible Mitigation Measures	Status
1	CO <sub>2</sub> accumulation in a secondary reservoir following unexpected vertical migration.	Containment	Safety	Pilot and Commercial	Thorough site characterization to confirm multi-seal integrity; monitor for any unexpected CO <sub>2</sub> migration (e.g. seismic surveys).	<b>Active</b> – strong multi-layer containment, no credible pathway identified.
2	Slow rate of CO <sub>2</sub> trapping in the reservoir (e.g. slower trapping or containment than expected).	Containment	Performance	Pilot and Commercial	Conservative injection design to ensure adequate residence time; pilot data will validate CO <sub>2</sub> trapping performance.	<b>Active</b> – no indication of containment issues (monitor long-term retention).
3	Leakage through operational injection well (well integrity failure leading to CO <sub>2</sub> escape).	Containment	Safety	Pilot and Commercial	Robust well design (corrosion-resistant casing, high-quality CO <sub>2</sub> cement) and integrity testing before operation; continuous wellbore pressure monitoring and emergency shut-in protocols; contingency plan (e.g. relief well) in place.	<b>Active</b> – Mitigated to ALARP in design (Round 2 analysis classified this leak risk as very low); ongoing integrity monitoring during injection.
4	Leakage through abandoned well (legacy well Do-1C) if CO <sub>2</sub> plume reaches it.	Containment	Safety	Pilot and Commercial	Abandoned well is 11.7 km away – plume not expected to reach it. Perform geophysical survey to locate and assess well condition; establish baseline water chemistry around well for early leak detection.	<b>Active</b> – Negligible risk for pilot (plume remains far from Do-1C); will continue monitoring in MMV plan as a precaution.
5	Leakage through caprock due to pressure build-up (fracture or caprock breach).	Containment	Safety	Pilot and Commercial	Strict pressure management – injection bottom-hole pressure kept well below fracture pressure; real-time pressure monitoring; multiple sealing formations above reservoir provide buffer.	<b>Active</b> – Mitigation in place (Round 2 modelling confirms caprock will remain intact under planned pressures – low risk).

Risk ID	Risk Description	Category	Type	Phase	Possible Mitigation Measures	Status
6	Leakage through caprock due to poor geologic characteristics (e.g. unexpected caprock permeability or discontinuities).	Containment	Safety	Pilot and Commercial	Extensive caprock characterization with new core and logs to confirm low permeability and strength; 3D seismic to detect any undetected discontinuities; design injection conservatively.	<b>Active</b> – No evidence of caprock deficiencies (thick, tight caprock; risk deemed negligible in Round 1).
7	Leakage through faults (migration along unseen or activated faults).	Containment	Safety	Pilot and Commercial	Site selection avoids faults; no major faults within ~8 km of injection well. Additional high-resolution 3D seismic will verify absence of faults. Injection pressure kept low to avoid fault reactivation.	<b>Active</b> – Classified as Not significant for both pilot and commercial phases. Will continue monitoring in MMV plan as a precaution
8	Chemical interaction of injected CO <sub>2</sub> with caprock (geochemical reactions weakening the seal).	Containment	Safety	Pilot and Commercial	Laboratory experiments on caprock reactive behaviour (using core samples); monitor geochemical indicators (e.g. pH, carbonate ions) in reservoir and seal formations; time-limited pilot minimizes exposure.	<b>Active</b> – Medium risk; minor geochemical effects expected in short term, will reassess with pilot data for long-term safety.
9	Insufficient/ineffective monitoring during storage (risk of undetected issues).	Containment	Safety	Pilot and Commercial	Comprehensive MMV plan using alternative monitoring techniques: downhole pressure/temperature gauges in injector, time-lapse 3D seismic, seabed CO <sub>2</sub> and pH sensors, and periodic remote surveys. This compensates for having no dedicated observation well.	<b>Active</b> – Being addressed via robust monitoring program; confidence in early anomaly detection.
10	Leakage through observation well (if a monitoring well is drilled, it could become a leakage pathway).	Containment	Safety	Pilot and Commercial	-	<b>Closed</b> – No separate observation well is planned for the pilot (risk eliminated by design).
11	CO <sub>2</sub> plume exceeds expected lateral extent, leading to non-anticipated spill points or leakage paths (e.g. migration out of structure).	Containment	Safety	Pilot and Commercial	Conservative storage capacity estimates and injection volumes; 3D reservoir modelling with uncertainty range (1,000-year simulations confirm plume remains within reservoir); time-lapse seismic to verify plume boundaries.	<b>Active</b> – Round 2 “worst-case” modelling showed CO <sub>2</sub> stays well confined in the intended reservoir (no spill).
12	Migration of formation brine outside expected area (displacement of high-salinity water into other formations or resources).	Containment	Safety	Pilot and Commercial	Offshore storage. No sensitive resources (e.g. potable aquifers) connect hydraulically to the storage zone.	<b>Closed</b> – Brine migration would have no impact in other resources
13	Reservoir over-pressurization due to unexpected	Containment	Safety	Pilot and Commercial	3D seismic to identify any internal flow barriers; design injection with ample pressure margin; real-	<b>Active</b> – Low risk for pilot (small volume); will update reservoir model



Risk ID	Risk Description	Category	Type	Phase	Possible Mitigation Measures	Status
	compartmentalization (undetected flow barriers cause pressure to rise more than predicted).				time pressure monitoring to catch abnormal build-up; contingency reduce pressure (e.g. brine production) if needed.	with pilot data to mitigate risk for commercial scale.
14	Pilot costs higher than estimated (budget overrun risk).	Economical	Performance	Pilot	Detailed project management and cost control; include contingency funds; optimize drilling and operational scheduling to prevent delays.	<b>Active</b> – Being managed through budgeting and funding oversight (no technical risks to storage safety).
15	Reduced injection capacity / lower well efficiency than expected (e.g. due to near-wellbore skin or formation damage).	Injectivity	Performance	Pilot and Commercial	Drill and complete injection well with best practices to maximize injectivity (e.g. appropriate perforation, damage control); perform injectivity tests and adjust injection rate as needed; maintain flexibility in injection schedule.	<b>Active</b> – Round 2 modelling indicates injectivity is sufficient, continue to monitor well performance (mitigate if any decline).
16	Precipitation effect around wellbore (salt or mineral precipitation reducing injectivity near well).	Injectivity	Performance	Pilot and Commercial	Baseline water sampling to assess brine salinity and scaling risk; injection plan to avoid excessive evaporation (manage bottom-hole temperature/pressure); if any injectivity decline is detected, apply mitigation (e.g. brief shut-in to dissolve salts, or inject solvent).	<b>Active</b> – monitor wellhead pressure for signs of halite scaling. In commercial phase, operational adjustments (rate optimization, possible stimulation) can address this.
17	Flow modifications in surrounding formations (e.g. groundwater flow changes within reservoir or adjacent layers caused by CO <sub>2</sub> injection).	Injectivity	Performance	Pilot and Commercial	Offshore storage. No sensitive resources connect hydraulically to the storage zone.	<b>Closed</b> – flow modifications in surrounding formations would have no impact in other resources.
18	Injectivity loss (significant decline in injectivity over time, potentially stopping injection).	Injectivity	Performance	Pilot and Commercial	Flexible well operations to mitigate injectivity drop: adjust rates, perform wellbore clean-outs or stimulations if needed. Pilot data will reveal any trends; for commercial scale, plan redundancy (e.g. ability to drill a supplemental injector if required).	<b>Active</b> – For longer-term injection, mitigation strategies exist (this uncertainty was considered “moderate risk at most” and is manageable).
19	Injectivity below expectations (reservoir overall permeability/capacity is lower than forecast).	Injectivity	Performance	Pilot and Commercial	Pilot phase as a learning test – use pilot injection results to recalibrate models and reduce uncertainty for full scale. Maintain conservative design margins; if needed, employ additional injection wells or longer injection period for commercial volumes.	<b>Active</b> – Ongoing evaluation; pilot results will likely improve confidence. Currently considered a low risk for both pilot and future scale-up.
20	Disruption by a later activity (e.g. future drilling, mining, or	Legal & Gov.	Performance	Pilot and	Early coordination with regulators to secure the storage site area against incompatible activities;	<b>Active</b> – very low likelihood during the pilot timeframe; will be managed



Risk ID	Risk Description	Category	Type	Phase	Possible Mitigation Measures	Status
	other operations intersecting or impacting the storage complex).			Commercial	monitor any new license applications in vicinity and engage authorities to prevent conflicts.	through regulatory permits and spatial planning.
21	Public resistance to the project (local community or NGO opposition delaying or halting the pilot).	Legal & Gov.	Stakeholder Management	Pilot and Commercial	Stakeholder engagement program – continuous outreach to local communities, fishermen, and authorities; transparent communication of monitoring data and safety measures; involve local stakeholders in a committee to address concerns.	<b>Active</b> – Ongoing and future communication aims to ensure public acceptance and trust in the project.
22	Lack of political will to implement the CCS project (policy or permitting support is withdrawn).	Legal & Gov.	Stakeholder Management	Pilot and Commercial	Proactive regulatory engagement: work closely with government and regulators to demonstrate alignment with climate goals; voluntarily meet high safety/environment standards to build confidence; leverage EU support.	<b>Active</b> – External risk. Mitigated by early regulator involvement and ensuring the pilot meets or exceeds permit requirements.
23	CO <sub>2</sub> –seal/fault rock interaction (chemical or mechanical effects of CO <sub>2</sub> on reservoir bounding rocks or faults).	Operational	Safety	Pilot and Commercial	Lab studies on cores to examine CO <sub>2</sub> /brine interaction with caprock and fault rock (mineral changes, friction); monitor for any anomalous pressure or microseismicity near faults that could indicate changes. Not a significant issue given lack of through-going faults at site.	<b>Active</b> – No major faults reached by CO <sub>2</sub> , and short pilot exposure limits any interaction effects.
24	CO <sub>2</sub> plume extent exceeds expectations and interacts with other subsurface resources (e.g. hydrocarbon reservoirs, aquifers).	Operational	Performance	Pilot and Commercial	-	<b>Closed</b> – There are no hydrocarbon fields or aquifers.
25	Unexpected seabed risks (e.g. seafloor instability, archaeological artifacts, or other marine hazards impacting operations).	Operational	Safety	Pilot and Commercial	Baseline will identify any anomalous occurrences at seabed and well may be repositioned accordingly	<b>Active</b> – To be evaluated in detailed engineering; no specific seabed issues identified so far.
26	Damage to the wellhead (e.g. from vessel impact or fishing gear), leading to a leak or shutdown.	Operational	Safety	Pilot and Commercial	Establish a safety exclusion zone around the injection site (no fishing or anchoring near well); robust wellhead design (subsea tree or protection structure); real-time monitoring of wellhead pressure to detect any damage immediately.	<b>Active</b> – Managed through marine safety measures and regulatory exclusion zones (to prevent third-party interference).



Risk ID	Risk Description	Category	Type	Phase	Possible Mitigation Measures	Status
27	Failure to ensure CO <sub>2</sub> is in supercritical phase in the reservoir (if P/T conditions are borderline, CO <sub>2</sub> might not stay supercritical).	Operational	Performance	Pilot and Commercial	Confirm reservoir pressure-temperature profile with new well data to ensure >74 bar and ~31°C; operate injection within parameters that maintain CO <sub>2</sub> in dense phase. If needed, adjust injection depth or pressure to keep CO <sub>2</sub> supercritical.	<b>Active</b> – Reservoir is ~800–1200 m deep (likely sufficient for supercritical CO <sub>2</sub> ); will verify with pilot well data.
28	Simultaneous operations interference (overlap with other activities at the injection site – e.g. maintenance or research operations causing conflicts).	Operational	Performance	Pilot and Commercial	Careful scheduling to avoid concurrent high-risk operations; integrated operations planning (coordinate any well workovers, surveys, or nearby projects so they do not conflict with injection schedule).	<b>Active</b> – Standard operational planning will avoid simultaneous activities that could pose a risk.
29	Drilling window missed or rig unavailability (timing delays impacting the project schedule/cost).	Operational	Performance	Pilot and Commercial	Advance contracting of drilling rig; flexibility in project timeline to accommodate seasonal/weather constraints; have backup options (alternate rig or window) identified.	<b>Active</b> – handled in project planning (could affect schedule but not storage safety; mitigation in place via project risk management).
30	Disruption of other uses in the area due to the CO <sub>2</sub> pilot.	Operational	Performance	Pilot and Commercial	Consult regional development plans to ensure no overlapping subsurface uses; engage with other operators if any to coordinate activities. Regulators to formalize priority of the CO <sub>2</sub> pilot in the license area to prevent conflicts.	<b>Active</b> – No conflicting subsurface use identified in the pilot area; will remain vigilant through regulatory channels.
31	Hazards from induced seismicity (injection-triggered micro-seismic events causing ground motion or concern).	Operational	Safety	Pilot and Commercial	Implement a Traffic Light System (TLS) for seismic monitoring and control – a dedicated microseismic array will detect any induced events in real time, with predefined thresholds to adjust or halt injection. Maintain injection pressure below levels that could induce faults.	<b>Active</b> – Continuous seismic monitoring in place; modelling indicates any induced seismicity would be too small to be felt. Protocols ready (TLS) to ensure seismic risk remains minimal.
32	Leakage as a result of natural seismicity (an earthquake damages storage integrity causing CO <sub>2</sub> leak).	Operational	Safety	Pilot and Commercial	The region’s seismicity is low, and the robust geological seals provide resilience. Well design accounts for worst-case ground motion. If a significant earthquake occurs, perform immediate inspections (well pressure, seabed survey) to check for any leakage. Contingency plans (including possible well intervention) in place.	<b>Active</b> – Unlikely during the pilot (short duration). No credible large quake scenario leads to leakage in analyses (containment remains secure under regional seismic loads).
33	Infrastructure damage from natural seismicity (earthquake damages surface or subsea)	Operational	Safety	Pilot and Commercial	Ensure facilities (wellhead, pipelines) are built to relevant seismic standards; have emergency shutdown systems that trigger on abnormal conditions. Post-earthquake inspection protocol to	<b>Active</b> – Low probability event. Emergency response plans exist for natural disasters; risk accepted with engineering safeguards.



Risk ID	Risk Description	Category	Type	Phase	Possible Mitigation Measures	Status
	facilities, e.g. wellhead, causing an incident).				quickly assess and repair any damage before resuming operations.	
34	CO <sub>2</sub> interaction with well cement and materials (long-term corrosion or degradation of wellbore integrity).	Operational	Safety	Pilot and Commercial	Use CO <sub>2</sub> -resistant cement and alloys in well construction; perform regular well integrity tests (cement bond logs, pressure tests) to check for any leaks. Monitor annulus pressure during injection for signs of casing/cement issues. Plug & abandon well with proper materials after operation.	<b>Active</b> – Negligible impact over the 3-years pilot. For the longer term, material selection and monitoring ensure any degradation is detected and managed.
35	Accidental over-filling (injecting or storing more CO <sub>2</sub> than planned, exceeding safe limits at surface or subsurface).	Operational	Safety	Pilot and Commercial	Strict accounting of injected CO <sub>2</sub> mass and injection rates; automated control systems to prevent overruns; training and procedures for operators to stop injection at the approved volume. Any temporary surface storage is designed with safety margins to prevent overflow.	<b>Active</b> – risk managed through operational controls. No instances expected (pilot volume is well-defined and limited by permit).
36	Impossibility of surface CO <sub>2</sub> storage (unable to buffer CO <sub>2</sub> on site if injection is interrupted, potentially causing venting or shutdown).	Operational	Performance	Pilot	Coordinate capture and injection rates to avoid the need for long-term surface storage. Include a small buffer storage capacity or divert route so that if injection stops, CO <sub>2</sub> can be temporarily stored or safely vented in a controlled manner. Obtain permits for emergency venting if needed and design procedures to minimize environmental impact.	<b>Active</b> – To be addressed in pilot design (ensuring injection reliability and contingency for any temporary storage/venting requirements).
37	NO <sub>x</sub> deposition in natural areas (emissions from drilling rigs or vessels depositing nitrogen oxides on sensitive habitats).	Operational	Safety	Pilot and Commercial	Use modern, low-emission equipment and adhere to emission regulations. Time operations to minimize impact (avoid peak breeding seasons in nearby protected areas, if applicable). Environmental monitoring (e.g. air quality) during operations to ensure compliance.	<b>Active</b> – Managed under environmental permitting (EIA requirements). The short duration and offshore location of the pilot mean any NO <sub>x</sub> impact will be limited.
38	Restrictions to fishing activities around the well location (exclusion zone affecting local fisheries).	Social	Stakeholder Management	Pilot and Commercial	Clearly communicate and enforce the safety exclusion zone during operations; engage local fishermen early to explain the pilot timeline and restrictions. Consider compensation or alternative arrangements if fishing grounds are temporarily inaccessible.	<b>Active</b> – handled through stakeholder engagement (fishermen representatives involved, transparency about exclusion timing).
39	Impact on touristic activities (e.g. charter fishing, diving, or	Social	Stakeholder Management	Pilot and Commercial	Inform local tourism operators about the project schedule and any visible activities (such as drilling	<b>Active</b> – No significant impact expected (offshore location, short



Risk ID	Risk Description	Category	Type	Phase	Possible Mitigation Measures	Status
	coastal tourism) due to the pilot operations.				rig presence). Ensure that onshore support operations avoid tourist-heavy areas or seasons when possible. Public outreach to emphasize the project's research nature and safety to avoid negative perceptions.	duration), but maintaining communication with community to address any concerns.
40	Loss of employment in other sectors (perceived negative economic impact on traditional industries due to CO <sub>2</sub> pilot).	Social	Stakeholder Management	Pilot and Commercial	-	<b>Closed</b> – Social risk monitoring. The pilot and commercial phases are expected to create jobs and lead to no loss of jobs at all. Ongoing stakeholder dialogue will ensure any misconceptions are addressed.
41	Permeability degradation during injection due to chemical/mineral precipitation in the reservoir (far-field effects reducing reservoir permeability).	Storage Cap.	Performance	Pilot and Commercial	Laboratory core-flood experiments to assess long-term mineral precipitation tendencies; monitor reservoir pressure and injectivity for any gradual decline. Over pilot's short duration, negligible effect expected. For commercial, adjust injection strategy (e.g. periodic pressure fall-offs to dissolve any precipitates).	<b>Active</b> – modelling in WP3 indicates residual mineral precipitation in a siliciclastic reservoir. Pilot will gather core and formation water data during pilot drilling to refine understanding of any long-term precipitation effects.
42	Undetected flow barriers in the reservoir (e.g. sub-seismic faults or stratigraphic baffles reducing effective storage volume).	Storage Cap.	Performance	Pilot and Commercial	Acquire high-resolution 3D seismic to detect smaller faults and heterogeneities; incorporate them into the static model. During pilot, closely analyse pressure propagation – if compartmentalization exist, pressure build-up will reveal them. Adjust field development plan (additional wells or pressure management) if significant barriers are identified.	<b>Active</b> – Uncertainty being reduced by new data. No major compartmentalization is evident in existing data (any minor barriers have not posed a risk in simulations).
43	Low average permeability (reservoir wide permeability is at the low end of expectations, limiting injectivity and capacity).	Storage Cap.	Performance	Pilot and Commercial	Use pilot well core and test data to refine permeability estimates across the structure; update dynamic models accordingly. If permeability is lower, ensure injection period is sufficient or consider multiple injection points for commercial scale. In the pilot, injection volume is small enough that even lower perm would still allow completion of injection (just at higher pressure).	<b>Active</b> – To be confirmed with pilot results. Current models (with uncertainty range) indicate adequate permeability to meet injection goals; risk is low and decreasing as more data are gathered.
45	Storage capacity below expectations (target of 15–	Storage Cap.	Performance	Commercial	Leverage pilot to “de-risk” the capacity: update volumetric estimates with real data. Early	<b>Active</b> – Pilot results will confirm actual capacity; mitigation plans



Risk ID	Risk Description	Category	Type	Phase	Possible Mitigation Measures	Status
	30 Mt for commercial phase cannot be met, undermining project economics).				engagement with stakeholders to manage expectations about achievable storage volumes.	(alternate sites or revised injection strategy) will be developed if necessary.

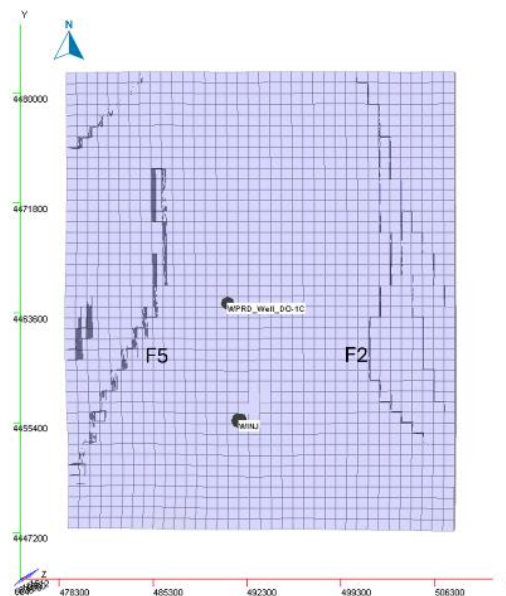


## Appendix 2 – Risk of leakage through abandoned well and faults

### 1 - Introduction

The CO<sub>2</sub> plume migration assessment carried out in WP5 confirms the robustness of the optimized injection strategy developed in WP3 for the PilotSTRATEGY Portuguese site. The final injection well location and well trajectory were selected using coupled flow–geomechanical optimisation methods to ensure that operational pressures remain sufficiently below the minimum stress thresholds needed to induce fracture propagation, caprock failure, or slip along any mapped fault structures.

The injection well is placed near the central part of the reservoir, within a high permeability layer identified during well-location optimization. It targets the deepest and most suitable reservoir interval at around 1200 meters depth, where a 50-meter perforation interval is included to ensure adequate injectivity and pressure management. The closest structural boundaries to the wells are fault F2 on the east side of the model and fault F5 on the west side, which constrain the overall geometry of the prospect (Figure 2.1).



*Figure 2.1: Plan-view of the dynamic simulation grid (800 m × 800 m cell size) showing the locations of the injection well (WINJ) and the legacy well (WPRD\_Well\_DO-1C). The map also displays the major interpreted faults F2 and F5.*

To quantify uncertainty in the long-term plume behaviour, the Round 2 analysis incorporated an expanded stochastic workflow supported by a Bayesian uncertainty algorithm implemented via AspenTech’s ENABLE software. The sampling approach updates prior geological and petrophysical probability distributions using dynamic simulation outputs and propagated uncertainty behaviour. The updated distributions reflect more realistic spatial variability in permeability, porosity, anisotropy, structural connectivity, fault transmissibility and Corey parameters. This refined uncertainty quantification results in a more accurate representation of plume geometry, storage trapping behaviour, and long-term migration probability.

Because simulation of a 1000-year period requires computational efficiency, the reservoir grid resolution was coarsened from 250 × 250 × 10 m (used in Khudhur et al. (2024) for optimisation) to

800 × 800 × 10 m for the long-term stochastic workflow (Figure 2.2). This coarser grid preserves the large-scale hydrodynamic behaviour responsible for plume migration while enabling 1,100 Bayesian stochastic realizations to be completed within feasible computation time. Each realization included 30 years of injection at the designed rate, followed by 970 years of post-injection modelling.

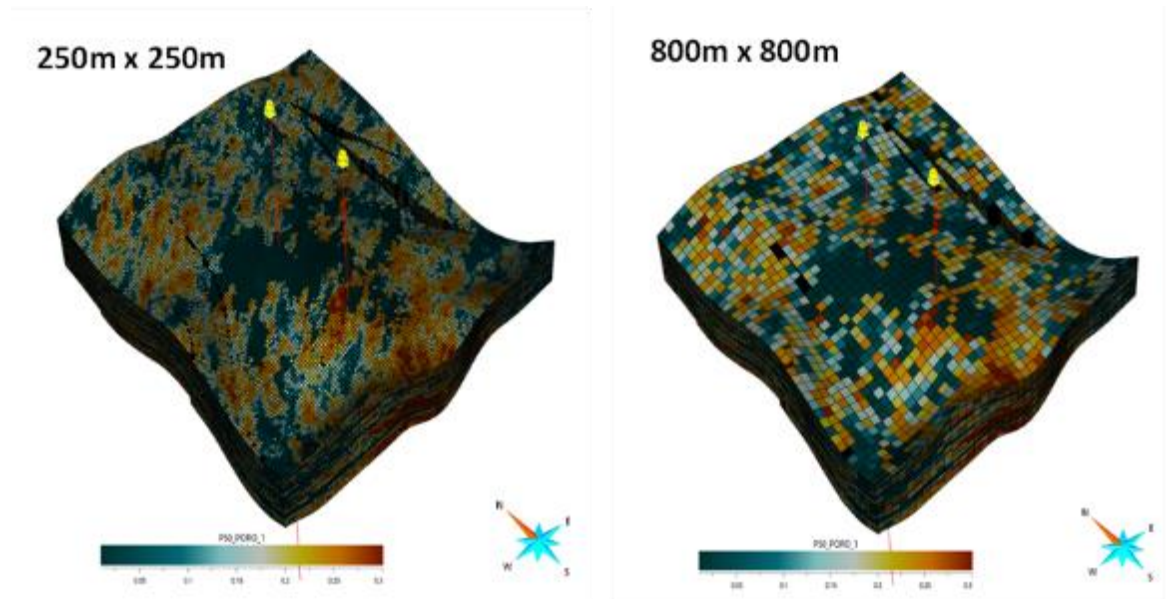


Figure 2.2: Comparison of grid resolutions used in dynamic CO<sub>2</sub> injection modelling. The left model (250 m × 250 m × 10 m) corresponds to the Khudhur et al. (2024) configuration. The right model (800 m × 800 m × 10 m) adopts coarser grid cells to reduce computational time while maintaining representative flow behaviour during the 1,000-year stochastic variation analysis.

## 2 - Implementing uncertainties

Geological uncertainties encompassed spatial trends in porosity, permeability, facies proportions, structural dip variation, shale fraction, sand connectivity and vertical layering continuity. These were parameterized using variogram-based geostatistical representations, with horizontal correlation ranges varying between 3000 and 7000 m, vertical correlation ranges between 5m and 50 m, and facies proportion limits bounded by minimum, maximum, and most-likely values derived from WP2 and WP3 datasets.

Petrophysical uncertainties included porosity, permeability, vertical anisotropy ratios, irreducible water saturation, residual gas saturation, and relative permeability behaviours. Table 2.1 lists all parameters included in the stochastic variation, the associated distributions, and the ranges used. Each parameter was sampled with either Pert or triangular distributions depending on the certainty and availability of supporting data. All 1100 realizations were generated by sampling from these distributions, allowing for adjustments during iterative simulation.

Corey parameters for gas and water were varied to generate a range of relative permeability curves ( $k_{rg}$  and  $k_{rw}$ ). These curves governed key flow behaviours, including saturation front movement, mobility ratios, viscous–buoyancy balance, and residual trapping. Normalized relative permeability was calculated from water saturation, irreducible water saturation, and residual gas saturation. Gas saturation followed from the same fixed endpoints. The Corey equations were then applied to compute  $k_{rg}$  and  $k_{rw}$ . Residual gas saturation controlled how much CO<sub>2</sub> became trapped, while the CO<sub>2</sub>

Corey exponent shaped the  $k_{rg}$  curve. Cases with weaker residual trapping or higher  $k_{rg}$  produced the widest and longest CO<sub>2</sub> plume footprints.

Table 2.1: Summary of geological and petrophysical parameters used for stochastic variation in the modelling.

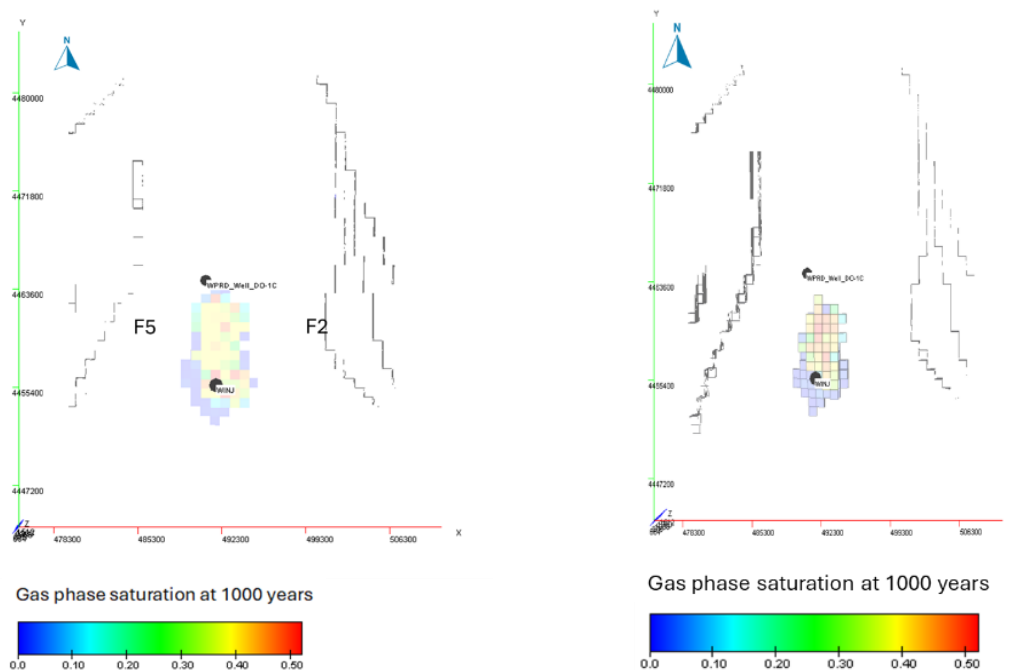
Name	Description	Active	Min	Max	Most Likely	Distribution
Azimuth	Orientation of the main structural trend guiding facies continuity.	Yes	30	60	45	Triangle
kr <sub>g</sub>	CO <sub>2</sub> relative permeability curve endpoint, influencing gas mobility.	Yes	0.15	0.83	0.35	Triangle
maximum_sand	Upper sand proportion limit defining facies heterogeneity.	Yes	0.3	0.44	0.35	PERT
maximum_shale	Upper shale proportion within stratigraphic units.	Yes	0.05	0.1	0.08	PERT
mean_sand	Average sand proportion used in geostatistical realizations.	Yes	0.13	0.23	0.18	PERT
mean_shale	Average shale content defining fine-grained heterogeneity.	Yes	0.03	0.07	0.05	PERT
minimum_sand	Lower sand fraction limit in lithological mix.	Yes	0.05	0.1	0.08	PERT
minimum_shale	Lower shale proportion defining base facies input.	Yes	0.001	0.05	0.03	PERT
ng	Corey exponent for CO <sub>2</sub> phase, defining relative permeability curvature.	Yes	2	5	3	Triangle
nw	Corey exponent for water phase.	Yes	3	7	5	Triangle
R_Max	Maximum horizontal correlation range in variogram model.	Yes	3000	7000	5000	PERT
R_Min	Minimum horizontal range defining heterogeneity continuity.	Yes	1500	6500	2000	PERT
R_Vertical	Vertical correlation range for geostatistical layering.	Yes	5	50	35	PERT
R_Vertical_facies	Vertical range used in facies simulation.	Yes	5	50	35	PERT
R_Vertical_permeability	Vertical anisotropy ratio for permeability.	Yes	5	15	10	PERT
R_Vertical_porosity	Vertical anisotropy ratio for porosity.	Yes	5	50	20	PERT
sorg	Residual gas saturation, representing immobile CO <sub>2</sub> fraction.	Yes	0.0029	0.15	0.05	Triangle
standard_deviation_sand	Variability in sand proportion across realizations.	Yes	0.03	0.08	0.05	PERT
standard_deviation_shale	Variability in shale proportion across realizations.	Yes	0.01	0.05	0.02	PERT
swc	Connate (irreducible) water saturation.	Yes	0.1	0.3	0.15	Triangle

The Bayesian algorithm used in this phase enabled integration of prior probabilities derived from WP2/WP3 data with the model outputs of the 1,100 simulations. The algorithm updated parameter weights dynamically to avoid unlikely parameter combinations and enforce convergence across the ensemble. Parameter combinations are considered **unlikely** when they are inconsistent with the geological and dynamic behaviour of the system. During the iterative stochastic workflow, such combinations are down-weighted, as they do not reproduce physically plausible plume or pressure responses, leading to convergence toward realistic parameter sets. This dynamic updating feature provides a foundation for later integration of pilot monitoring data into the uncertainty framework.

### 3 - Results

The ensemble of 1100 simulations produced a broad distribution of plume footprints, pressure histories, and CO<sub>2</sub> mass balances. The plume evolution patterns were mapped at the end of the 1000-year simulation period. High-mobility cases exhibited broader lateral spread but remained confined within the structural limits of the reservoir. Low-mobility cases showed more compact plumes centred near the injection location.

Realisation 293 is the one with the CO<sub>2</sub> migration closest to the legacy well Do-1C. After 1000 years of migration and stabilization, the plume front advanced to within approximately 800 meters of the legacy well, as indicated by free-phase CO<sub>2</sub> saturation footprint shown in Figure 2.3.



*Figure 2.3: Gas-phase CO<sub>2</sub> saturation after 1,000 years for realisation 293 (left) and realisation 168 (right). A total of 47 million tons was injected over 30 years, and the plume migrated northward toward the legacy well WPRD\_Well\_DO-1C, approaching to within approximately 800 m. The injection well WINJ lies between bounding faults F5 and F2, which constrain plume movement within the reservoir compartment.*

The gas-phase saturation footprint shows that the CO<sub>2</sub> plume, has migrated preferentially northward and upward within the reservoir. This movement is strongly influenced by the underlying geological structure: the prospect is characterized by an anticline geometry that dips southward and rises toward the north. As a result, buoyant CO<sub>2</sub> tends to accumulate and advance along this structural axis.

Across all 1100 realizations, no scenario shows the plume reaching the legacy well Do-1C or the bounding faults F2 and F5 (Figure 2.6). Furthermore, in the extremely conservative realizations where the plume advances furthest, CO<sub>2</sub> saturation remains very low, typically below 0.05, meaning that even if the plume were to reach those areas, the probability of effective leakage is extremely low, and the potential impact would be minimal. This is due to saturation-dependent relative permeability effects and pressure decay, both of which strongly limit CO<sub>2</sub> mobility at plume fringes.

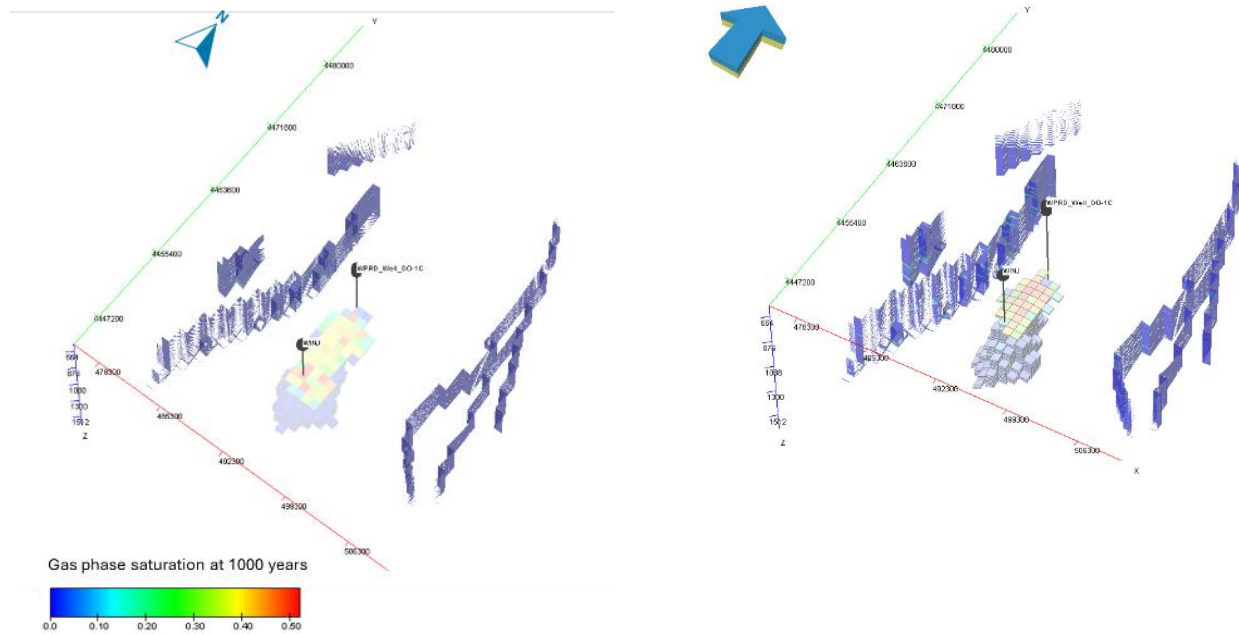


Figure 2.6: Free-phase CO<sub>2</sub> saturation after 1000 years for realization 293 (left) and realization 178 (right), shown here from a different viewing angle, illustrating the case in which the plume migrates closest to the legacy well (WPRD\_Well\_Do-1C), but still at more than 800 m distance.

These outcomes demonstrate that the likelihood of CO<sub>2</sub> leakage through the legacy well or fault structures is extremely low. Even in theoretical limit cases where the plume might migrate beyond typical boundaries, its saturation would be very low—indicating minimal buoyant or mobile CO<sub>2</sub> phase—thus making any potential impact negligible from both a safety and regulatory standpoint.

Nevertheless, because the physical condition of the legacy well remains uncertain, it is recommended that a full wellbore integrity assessment be undertaken, including ultrasonic scanning, cement bond logging and verification of annular isolation. This will ensure that the final risk classification of legacy-well leakage hazards is consistent with both modelling outcomes and the actual subsurface condition.

## Appendix 3 – Risk of natural and induced seismicity

### 1 - Introduction

Capture of CO<sub>2</sub> and its subsequent storage in suitable geological repositories can be a key technology for meeting net zero targets. However, the injection of large volumes of CO<sub>2</sub> into the subsurface can lead to large-scale pressurization and carry the risk of induced seismicity events. This can raise safety concerns, so that induced seismicity risk must be properly managed to ensure the successful development of geologic carbon sequestration projects.

A potential target site for a geologic carbon sequestration pilot project is under study in the offshore of Figueira da Foz (Portugal). The fact that the area has a small number of natural seismic events and that the carbon storage operations are being planned in the offshore significantly reduces the potential risks. Nevertheless, analysing and communicating natural and induced seismicity risks is key for technical robustness and social acceptance.

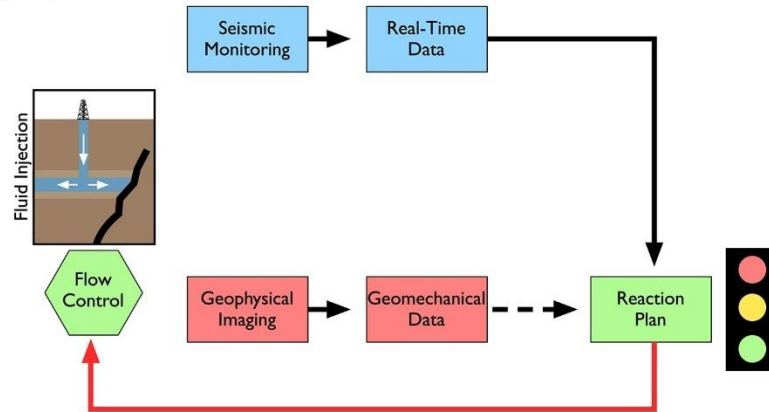
The objective of this study is fourfold: 1) a probabilistic analysis of natural seismic risk is carried out in order to understand the probability of natural seismic events of a certain magnitude occurring over a given period; 2) a probabilistic analysis of the slip tendency of pre-existing and hypothetical undetected faults is performed to understand if the planned injection fluid pressure will activate those structures and cause injection-induced seismicity; 3) a probability seismic hazard assessment is done considering linear and areal sources to assess induced seismicity risk; and 4) it is proposed a potential Traffic Light System to help the decision-making process related to injection operations and define guidelines to CO<sub>2</sub> injection operation in the target site.

### 2 - Analysis of the natural seismicity and seismic hazard

The Operational Forecasting of Induced Seismicity (ORION) toolkit was used in this study to carry out an analysis of the natural seismicity and seismic hazard in the region around the prospect site for geologic carbon sequestration in the offshore of Figueira da Foz (Portugal). ORION is an open-source toolkit developed by Lawrence Livermore National Laboratory and Lawrence Berkely National Laboratory to support decision making on seismic hazard analysis and risk management for geologic carbon sequestration (Kroll et al., 2024a, b). ORION is based on an Adaptive Traffic Light System where decisions are based on a forward looking probabilistic and adaptive framework. In contrast with the first-generation Traffic Light Systems (commonly included in the regulations of different countries; Figure 3.1a), these second-generation systems are fully probabilistic, adaptive (in the sense that new data is integrated on the fly to update geomechanical and seismicity forecasting models) and risk-based, integrating hazard, exposure, and vulnerability (Figure 3.1b; Grigoli et al., 2017).

As illustrated in the workflow (Figure 3.1), one key component of ORION is a seismic catalogue since this toolkit uses a data-driven forecasting methodology (Kroll et al., 2024a). Therefore, to answer the first objective of this work, two datasets were used. This first is a compilation of the seismic events from the IPMA (*Instituto Português do Mar e da Atmosfera*) archives and the other is seismic data acquired within the scope of the PilotSTRATEGY project.

### a) Classical Traffic Light Systems



### b) Adaptive Traffic Light Systems

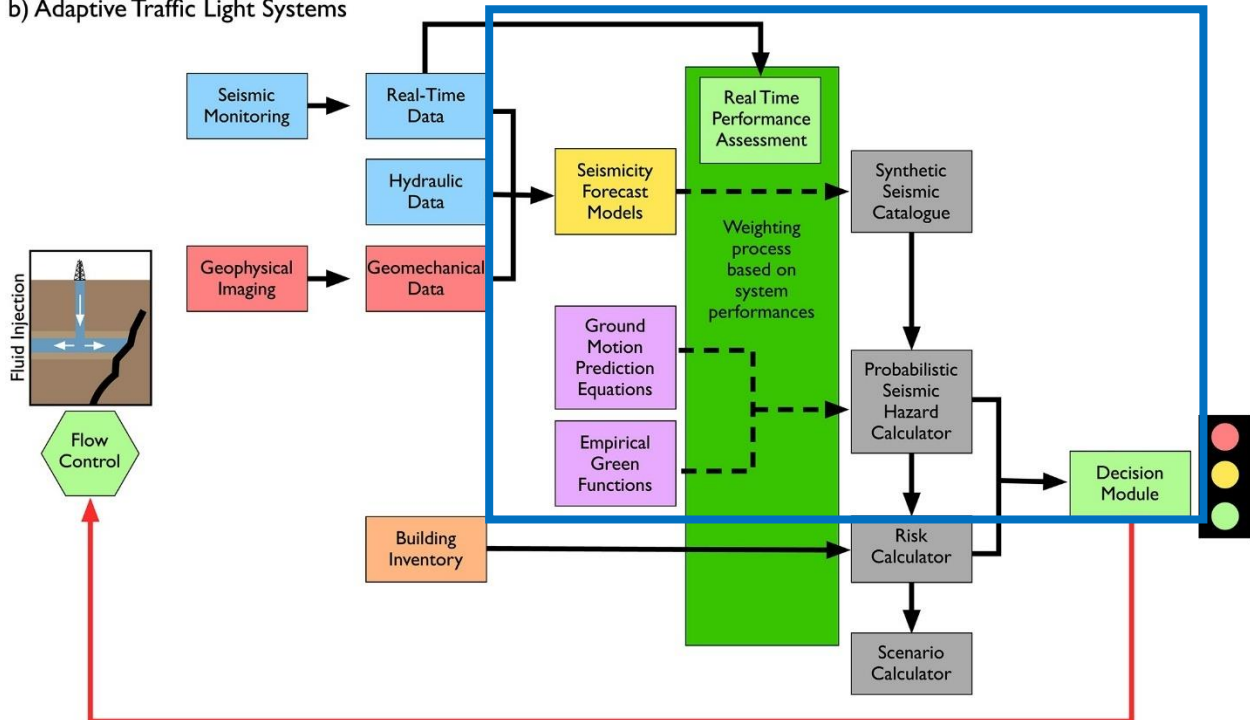


Figure 3.1. a) Classical Traffic Light System. In Classical Traffic Light Systems decisions are based on magnitudes and ground motions. Thresholds are defined in a static way taking geomechanical information into account. b) Adaptive Traffic Light System. In Adaptive Traffic Light System decisions are based on a forward looking, probabilistic, and adaptive framework (Grigoli et al., 2017). The blue square highlights ORION workflow and derived products (Kroll et al., 2024b).

## 2.1 - IPMA database

The IPMA database contains records of seismic events from 1961 to 2024. However, as in ORION date and time need to be transform in Unix epoch (i.e., number of seconds since January 1, 1970), seismic data older than January 1, 1970, was not considered. This corresponds to 31 data entries from a total of 3,426 events recorded within latitudes of 38 to 41° and longitudes of -8 to -11°.

The seismic catalogue from IPMA comprises 54 years of earthquake records and the number of events as a function of their magnitude, the Gutenberg-Richter parameters and the variation of the Gutenberg-Richter  $b$ -value over time are illustrated in Figure 3.2. ORION estimates the  $b$ -value based

on two methods: the maximum likelihood estimate method which requires estimates of the magnitude of completeness and the  $b$ -positive method which does not require an estimate of the magnitude of completeness. The second method was selected to estimate the  $b$ -value in this work.

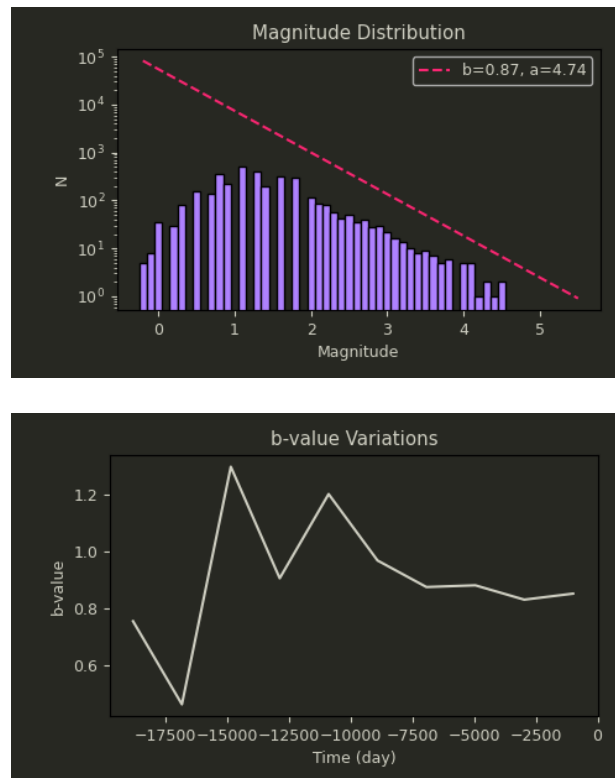


Figure 3.2. At the top, the magnitude distribution of earthquake events within the catalogue is shown together with the best-fit Gutenberg-Richter parameters. At the bottom, the variation of Gutenberg-Richter  $b$ -value over time is displayed.

In addition, the temporal variation of magnitudes in the seismic catalogue is illustrated in Figure 3.3. The distribution of magnitudes illustrates the technological progress of the seismic network over the years. After 2009, the seismic network was able to record earthquakes of lower magnitude than before.

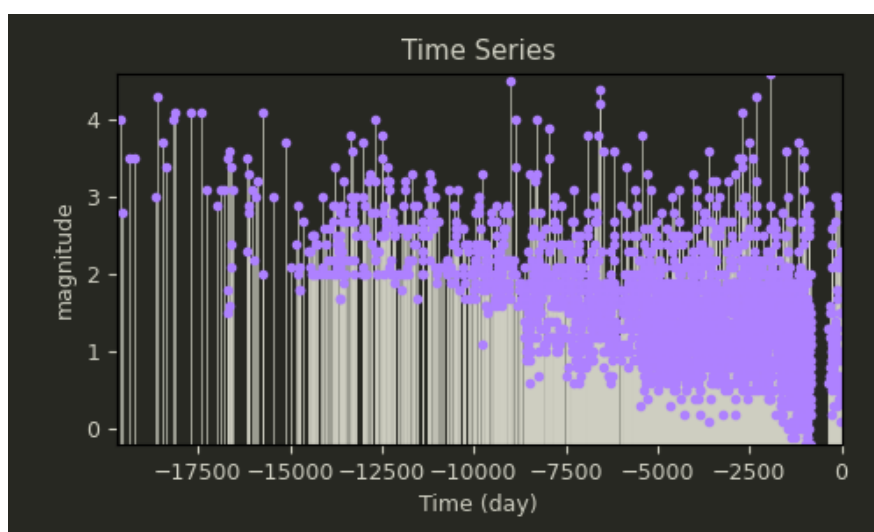


Figure 3.3. Magnitude distribution of earthquake events within the catalogue over time.

Figure 3.4 shows the location of the seismic events within the UTM coordinates  $x = [45000, 550000]$  m and  $y = [4400000, 4500000]$  m. This large grid of 100,000 m (x-direction) per 100,000 m (y-direction) was selected to provide a broader view of the location of the natural seismic events in relation to the prospect site (red triangle; Figure 3.4). As can be seen, near the injection well site, seismic events are less numerous than in other offshore and onshore areas.

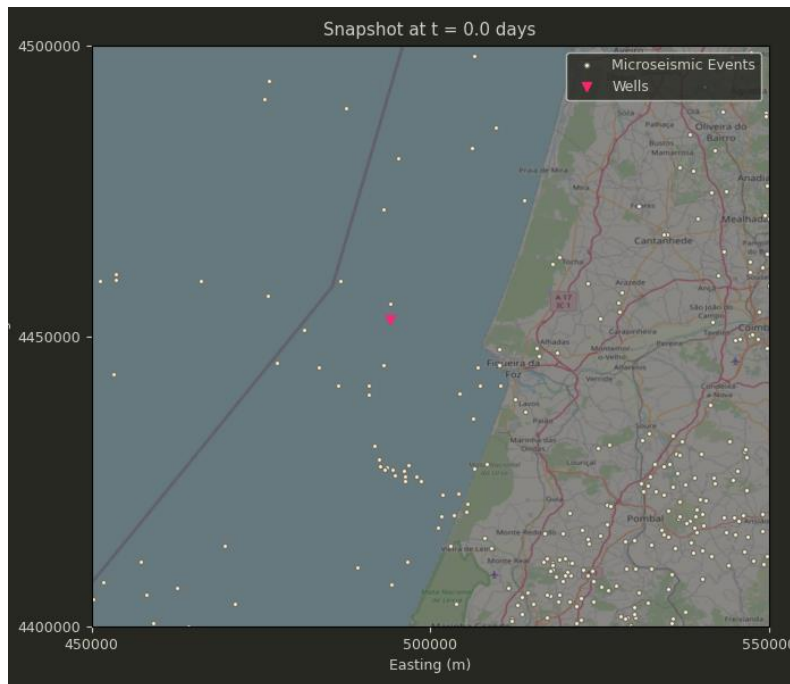


Figure 3.4. Location of the injection well (red triangle) and of the seismic events within the selected grid. The time  $t = 0.0$  days corresponds to a reference time of 29/06/2024, i.e., the last seismic event within the catalogue.

## 2.2 - PilotSTRATEGY database

The seismic data collected within the scope of the project has about 1 year of recorded events. The acquisition started on January 26, 2023, and finished on December 30, 2023. This corresponds to 154 seismic events with the spatial distribution shown in Figure 3.5 within the UTM coordinates  $x = [450000, 550000]$  m and  $y = [4400000, 4500000]$  m. The number of seismic events recorded around the injection well location is also very low.

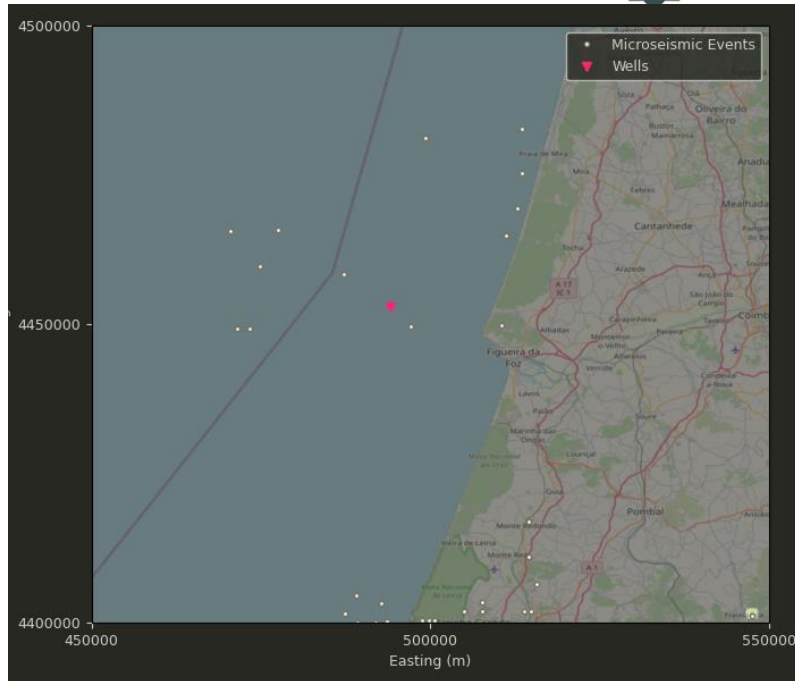


Figure 3.5. Location of the injection well (red triangle) and of the seismic events within the selected grid. The time  $t = 0.0$  days corresponds to a reference time of 30/12/2023, i.e., the last seismic event within the catalogue.

The number of events as a function of their magnitude and the magnitude of events over time are shown in Figure 3.6. As can be observed, the events recorded within the scope of PilotSTRATEGY have lower magnitudes than the IPMA catalogue. The  $b$ -value was also estimated through the  $b$ -positive method.

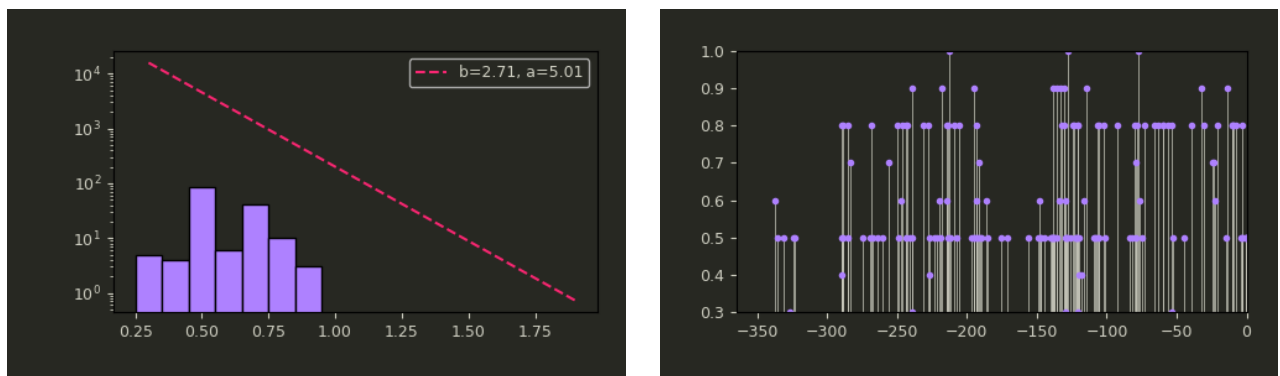


Figure 3.6. On the left it is shown the magnitude distribution of earthquake events within the catalogue and the best-fit of the Gutenberg-Richter parameters, and on the right, it is shown the magnitude distribution of earthquake events within the catalogue over time.

### 2.3 - Natural seismic hazard probabilistic analysis

ORION can compute seismicity forecasts based on physics-based models such as the coupled Coulomb rate-state model and the rate-state Ordinary Differential Equation model and based on statistical models such as the Seismogenic Index (Kroll et al., 2024a). Another forecasting model implemented in ORION is the Seismic Activity due to Injection. In addition, and as the performance of individual

seismic forecasting methods vary depending on site conditions and user configuration parameters, ORION generates an ensemble or best guess forecast to address this issue.

To answer the first objective of this study, we focused on the Seismogenic Index forecast model and used both the IPMA and PilotSTRATEGY catalogues. The Seismogenic Index Model is defined in ORION considering the coefficient of friction, typically assumed 0.4 for sandstone reservoirs (Vilarrasa and Carrera, 2015), and the tectonic shear and normal stressing rates. As these parameters are currently unknown for the study site, a literature-based tectonic loading rate was used. According to Neves et al. (2014), the tectonic loading rate in mainland Portugal is very low, between 0.05 to 5 MPa/10000 years. Therefore, a value of 0.5 kPa/yr was used for the tectonic shear and normal stressing rates.

The natural seismic hazard probabilistic analysis was carried out at two different scales (regional and local) for a better understanding of the risk of natural seismic events nearby the injection well, and the probability of those events to exceed a certain magnitude over a certain period of time.

The earthquake magnitude scale shown in Figure 3.7 was used to constrain the magnitudes of events of interest for the probabilistic analysis.

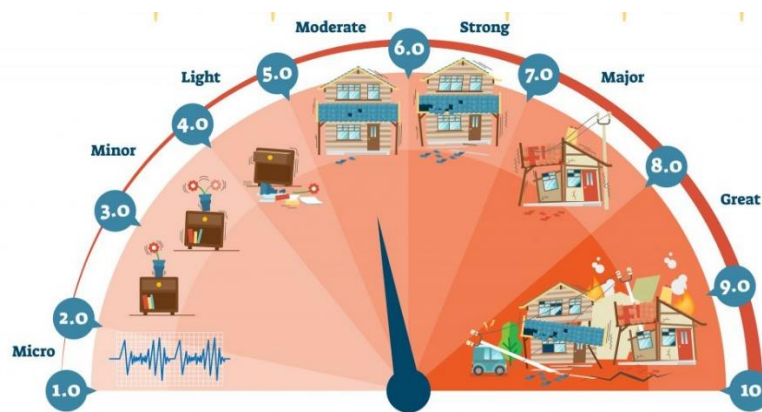


Figure 3.7. Diagram illustrating earthquake magnitude levels and Richter scale seismic activity (GeoVera, 2023).

### 2.3.1 - Regional scale

The regional scale considered the area illustrated in Figures 3.4 and 3.5. Figure 3.8 shows a time series plot displaying the observed number of events, the estimated number of events produced by the Seismogenic Index forecast model, and the ensemble forecast. As displayed in Figure 3.8, for the area considered, about 150 seismic events occurred since 1970 until 2024.

Based on the information within the seismic catalogue, a seismic hazard probabilistic analysis was carried out for a period of 100 years and revealed the results illustrated in Table 3.1 considering the earthquake magnitude of events that can be felt by the population (2 to 10; Figure 3.7). As a recall, these probabilities consider all the events within the grid of Figures 3.14 and 3.5.

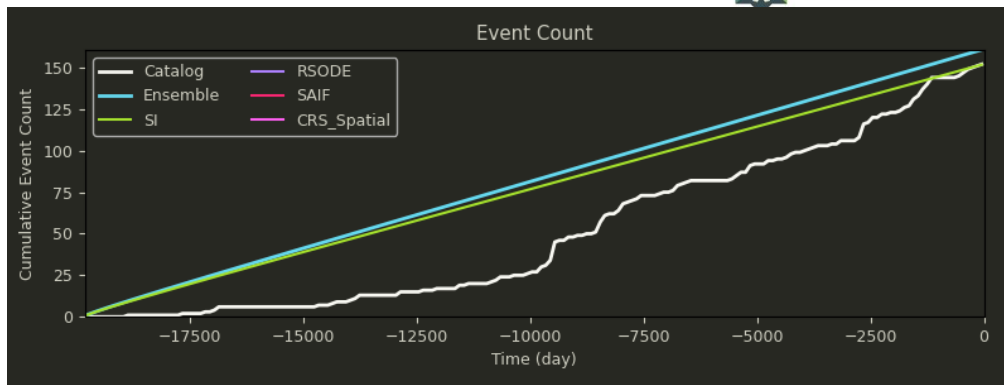
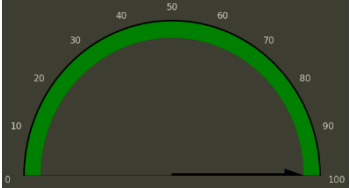




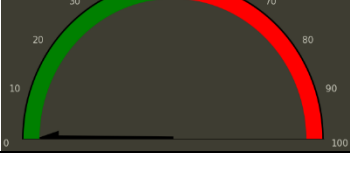


Figure 3.8. Time series plot of observed and estimated events. SI – Seismogenic Index forecast model.

Table 3.1. Probabilistic analysis of natural seismic events at regional scale.

Magnitude (-)	Period (years)	Probability (%)	
2.0	100	100	
3.0	100	100	
4.0	100	< 80	
5.0	100	< 20	
6.0	100	< 5	
7.0	100	0	

The events with magnitudes within 2.0 and 4.0 are common in the region and therefore their probabilities are shown in green. The events with magnitudes greater than 5.0, on the other hand, are uncommon, and for that reason, probabilities above 50% are shown in red.

As shown in Table 3.1, events within the minor to light magnitude scale (2.0 to 5.0; Figure 3.7) are the ones with the greatest probability of occurrence within the next 100 years and are also the more common within the grid selected (Figure 3.2). On the other hand, events with magnitudes above moderate ( $> 5.0$ ; Figure 3.7) have the lowest probability of occurrence and are also uncommon in the area selected for analysis (Figure 3.2).

### 2.3.2 - Local scale

The local scale is focused in an area around the injection well. A grid with UTM coordinates  $x = [484000, 504000]$  m and  $y = [4443000, 4463000]$  m was chosen for this analysis (Figure 3.9). Only 5 natural seismic events occurred within a  $400 \text{ km}^2$  around the injection well since 1970 until 2024.

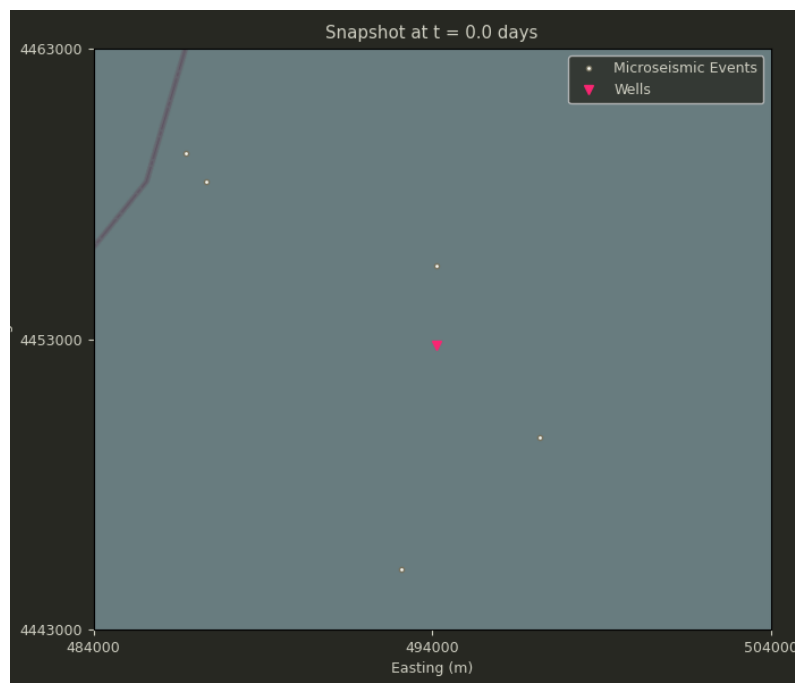


Figure 3.9. Location of the injection well (red triangle) and of the seismic events within the selected grid. The time  $t = 0.0$  days corresponds to a reference time of 29/06/2024, i.e., the last seismic event within the catalogue.

The time series plot displaying the observed number of events, the estimated number of events produced by the Seismogenic Index forecast model, and the ensemble forecast are shown in Figure 3.10. Table 3.2 shows the results of the probabilistic analysis for events of magnitude from 2.0 to 5.0.

The events with magnitudes within 2.0 and 4.0 are common in the region and therefore their probabilities are shown in green. The events with magnitudes greater than 5.0, on the other hand, are uncommon, and for that reason, probabilities above 50% are shown in red.

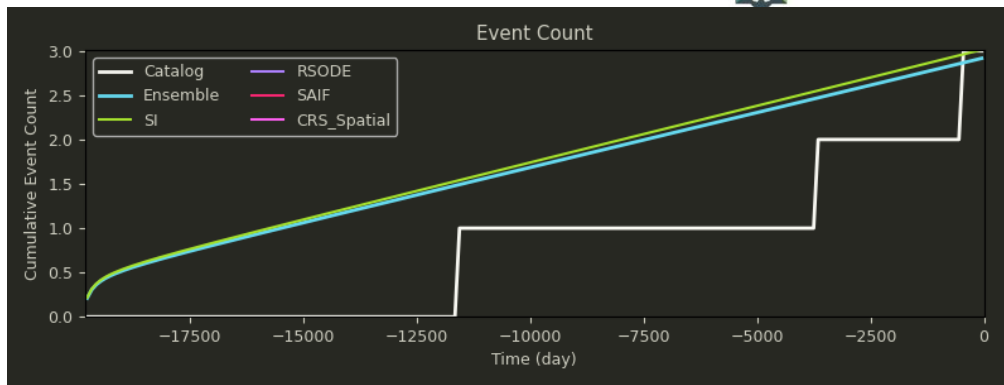
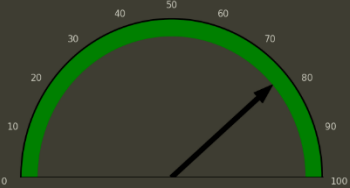





Figure 3.10. Time series plot of observed and estimated events. SI – Seismogenic Index forecast model.

Table 3.2. Probabilistic analysis of natural seismic events at local scale.

Magnitude (-)	Period (years)	Probability (%)	
2.0	100	< 80	
3.0	100	< 20	
4.0	100	< 5	
5.0	100	0	

### 3 - Analysis of induced seismicity risk

The injection of fluids in a reservoir can lead to pressure build up, altering the state of stress of the reservoir. This change of the in situ stable conditions becomes particularly important if fractures are present within the reservoir and if those structures are optimally oriented to slip and at a critical state of stress. For this reason, a probabilistic analysis of the slip tendency and activation potential of pre-existing fractures within the reservoir was carried out with the software FSP (CISR, 2023).

FSP stands for Fault Slip Potential and is a toolkit that was released in 2017 and was co-developed by the Stanford Center for Induced and Triggered Seismicity and ExxonMobil. FSP is a free tool for

deterministic and probabilistic screening of the rupture stability of existing fractures in contact with a reservoir undergoing a pore pressure change, typically near injection wells (CISR, 2023). The tool combines Mohr-Coulomb analysis with pore pressure modelling. FSP uses semi-analytic pressure modelling of a uniform confined aquifer using constant, isotropic parameters and linear superposition of a single or multiple wells. FSP can also be used to assess the rupture stability of fractures in the natural state or as influenced by uniformly perturbed conditions. Fractures are assumed to be in contact with the injection interval and out-of-zone effects and poroelasticity are not considered (CISR, 2023). FSP workflow is illustrated in Figure 3.11.

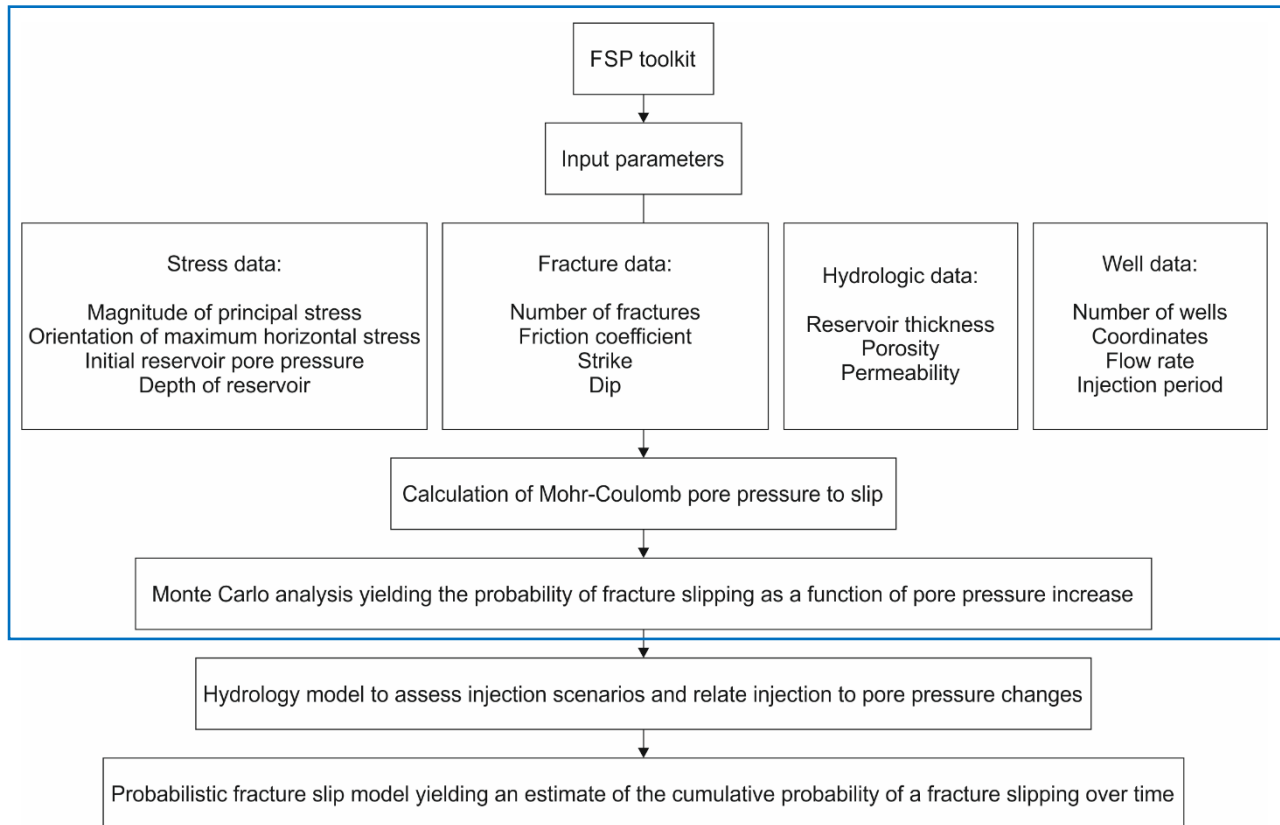


Figure 3.11. FSP workflow. The blue rectangle highlights FSP products of interest for this study.

### 3.1 – *In-situ* stress

The definition of the *in-situ* stress conditions is a key component to evaluate induced seismicity risk. Ribeiro et al. (1996) present estimates for the stress pattern in Portugal and adjacent Atlantic region, and the mean azimuth of 145° for the maximum horizontal stress direction was used in this study. As the three main components of the stress field can be assumed orthogonal, the minimum horizontal stress was estimated to have an azimuth of 235°, and the vertical stress component was assumed vertical. The plunge of the horizontal stresses was assumed 0° in this study.

Information about the magnitude of the principal stress components was not found during the literature review, and for this reason, an approximated estimation was used based on information provided by stakeholders. The study site is believed to be in a normal faulting regime, and the magnitude of the principal stress components is thus:

$$\begin{cases} S_V = 25 \text{ MPa/km} \\ S_{H_{\max}} = S_V = 25 \text{ MPa/km} \\ S_{h_{\min}} = 0.8S_V = 20 \text{ MPa/km} \end{cases} \quad (1)$$

The initial reservoir pore pressure prior injection was estimated in a previous task of the project, and the reservoir flow model suggests values ranging from 5.6 to 14.5 MPa with an average value of 9.8 MPa for the whole reservoir volume.

### 3.2 - Radial flow model

Although a detailed reservoir flow model is being developed as part of the PilotSTRATEGY WP3, a radial flow model assuming a homogenous confined aquifer was utilised to estimate the pressure front value at the centre of the reservoir and its dispersion with distance. This radial flow model was estimated for a reservoir with a thickness of 50 m and for a constant injection rate of 15 kg/s over a 30-year period. The results show that, at the injection point, the pressure increase is approximately 150 psi (or 1 MPa) decreasing logarithmic with the distance (Figure 3.12).

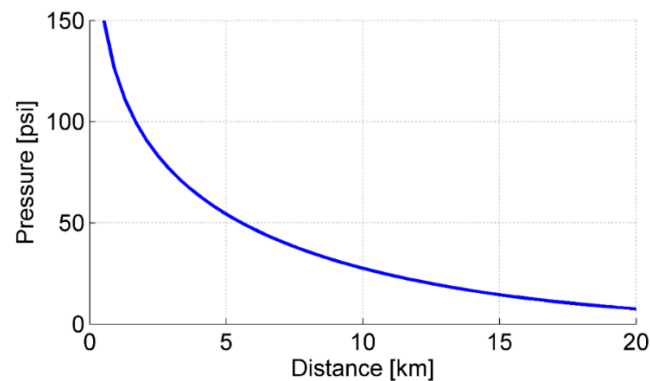


Figure 3.12. Radial flow solution at the end of the injection period.

### 3.3 - Slip tendency analysis and reactivation potential of pre-existing faults

The target reservoir is bounded by two main fault zones, of which a simplified conceptual model of the pre-existing faults is shown in Figure 3.13.

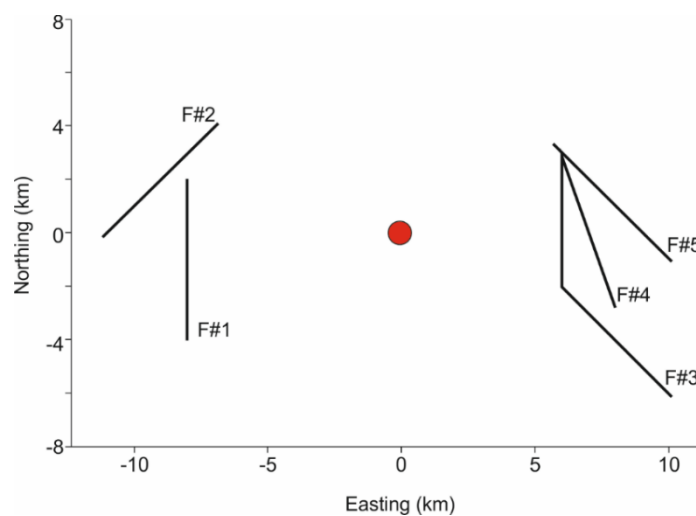


Figure 3.13. Simplified geological conceptual model used in FSP for the slip tendency analysis. The red dot indicates the injection well.

Considering this simplified analysis using Mohr-Coulomb criteria and the in-situ stress field estimated for the study site and a coefficient of friction of 0.4 (typical for sandstone reservoirs; Vilarrasa and Carrera, 2015), the majority of these pre-existing faults are optimally oriented to slip, but not at a critical state of stress (Figure 3.14). These pre-existing faults may be reactivated if the pore pressure nearby these structures increases between 1048 psi (7.2 MPa) and 2357 psi (16.3 MPa). These calculations were carried out for a reference depth of 1250 m which corresponds to the depth of the bottomhole section of the injection well.

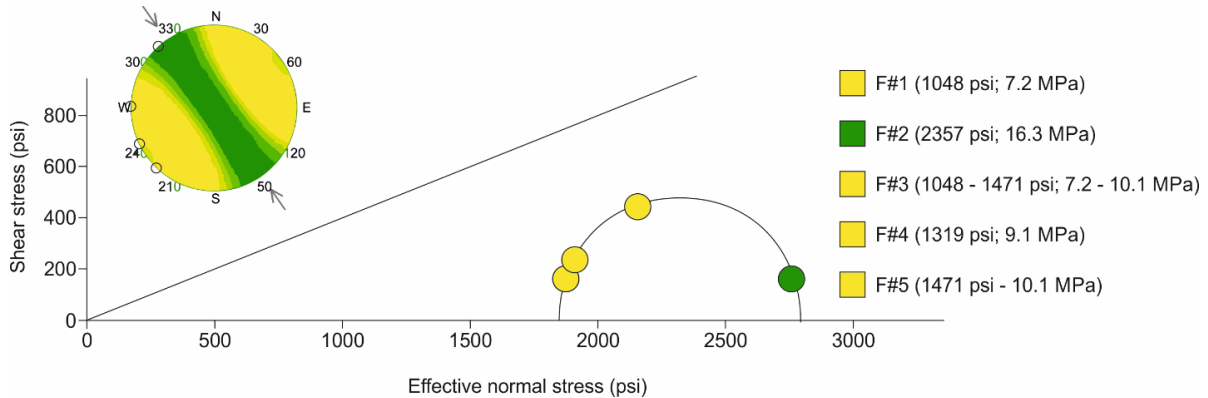


Figure 3.14. 3D Mohr diagram and stereonet showing fault projections and the increase in pore pressure required to induce slip in each fault. Each point in the 3D Mohr diagram corresponds to a fault plane and each point in the stereonet to a fault pole. The arrows in the stereonet indicate the maximum horizontal stress direction. 1 psi = 6.89 kPa.

As all the geomechanical input parameters used in the Mohr-Coulomb analysis are uncertain, a probabilistic analysis was also carried out. The uncertainty assumed for each input variable is illustrated in Figure 3.15a, and the cumulative distribution curves displaying the probability of slip of each fault for a certain pore pressure increase is shown in Figure 3.15b and 3.15c.

The probabilistic slip tendency analysis suggests that the quasi-optimal oriented faults have a probability of slip of 17% (Figure 3.15) for the pressure increase simulated at the faults' location (approximately 30 psi; Figure 3.12). It is thus important to keep the pore pressure nearby these structures below this threshold value for the target site to be considered safe for CO<sub>2</sub> storage.

### 3.4 - Slip tendency analysis of hypothetical undetected pre-existing fractures

The previous section analysed the slip tendency of known pre-existing faults located relatively far away from the injection well. In this section, the slip tendency of hypothetical fractures that may exist but haven't been detected, will be analysed. These undetected structures can become a major issue during CO<sub>2</sub> injection and therefore it is important to understand if there is a chance of any such structures to slip at the maximum allowed injection pressure (16.5 MPa) and expected pore pressure increase (1 MPa).

Analysis of the fracture network nearby the prospect site suggests two main families of fractures: NNE-SSW and ESE-WNW (Barata, 2024). The strikes were therefore estimated to range between 12-17° and between 106-108° with dips ranging between 85-90° for the first fracture set and between 75-90° for the second set (Barata, 2024). Considering these results, a total of 50 random fractures were generated with strikes ranging from 12 to 108° and dips varying between 75 and 90°. These are randomly located within a reservoir grid of 5×5 km (Figure 3.16).

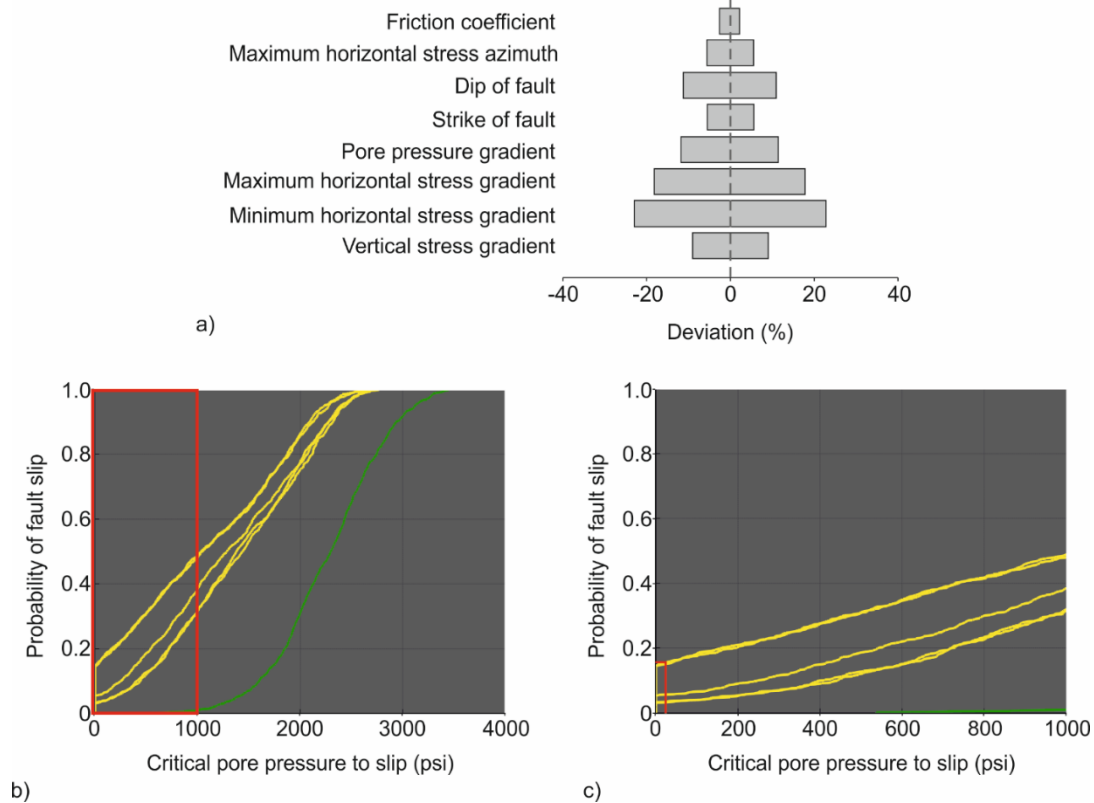


Figure 3.15. a) Variability of each input parameter used in the Monte Carlo analysis, b) cumulative probability function of slip on each fault as a function of pore pressure increase and c) zoom-in to show probabilities of slip at pore pressure increase below 1000 psi. Each curve represents a fault. 1 psi = 6.89 kPa.

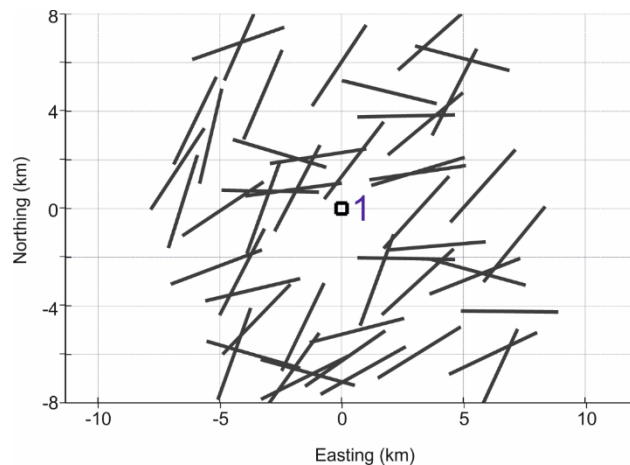


Figure 3.16. Map of hypothetical fractures randomly generated and location of the injection well.

Assuming the estimated in-situ stress field and a friction coefficient of 0.4, these structures are not at critical stress conditions, and the quasi-optimally oriented fractures can be activated, or will tend to slip, at a critical pore perturbation greater than 6.9 MPa at the depth of the well bottomhole section (i.e., at a depth of 1250 m; Figure 3.17).

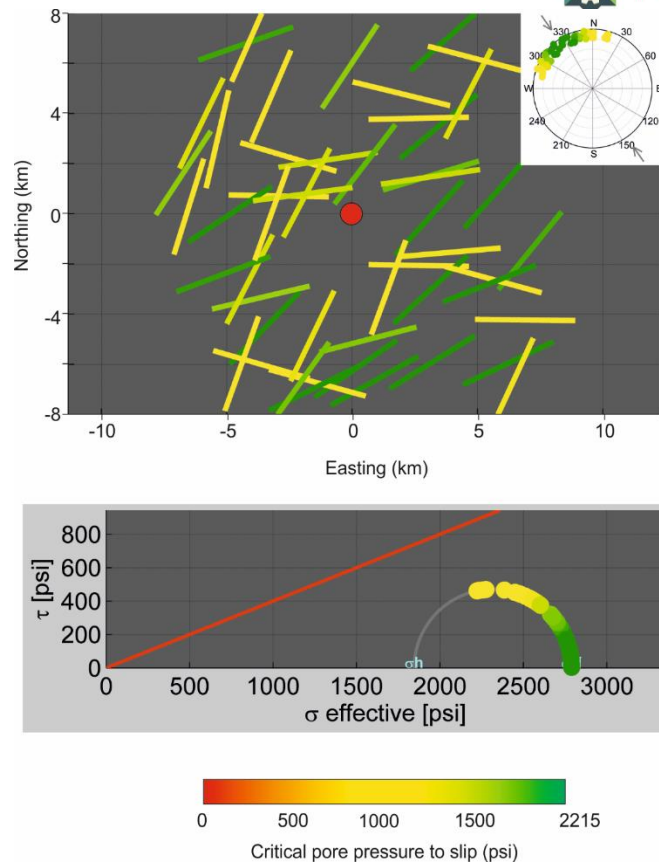


Figure 3.17. Top figure shows the map of hypothetical fractures generated and critical pore pressure to trigger slip in each hypothetical fracture and the stereonet with projection of the fracture poles. Bottom figure shows the 3D Mohr diagram for the average stress magnitude at the depth of 1250 m. 1 psi = 6.89 kPa.

As the critical pore pressure perturbation to trigger slip is expressed as  $\Delta P = P_{\text{injection}} - P_p$  (e.g., Miranda et al., 2023), then the quasi-optimal oriented structures located near the injection well could be activated at a fluid injection pressure of 16.7 MPa, which is higher than the maximum allowed injection pressure (16.4 MPa).

As many of the input parameters used in the analysis are uncertain, and this uncertainty will have an influence on the results, it therefore needs to be considered. Assuming the variability of the inputs shown in Figure 3.15a, a probabilistic analysis of the critical pore pressure to trigger slip was carried out (Figure 3.18). This analysis reveals that there is about 20% probability of the quasi-optimally oriented fractures to slip at a critical pore pressure perturbation of 150 psi (1 MPa; Figure 3.18). As the pressure front decays exponentially with distance to the injection well (Figure 3.12), if these quasi-optimal oriented structures are located far from the injection well, then their probability to slip decreases. At the limits of the reservoir, the simulated pore pressure increase is 0.2 MPa (30 psi), meaning a probability to slip of 17% (Figure 3.18).

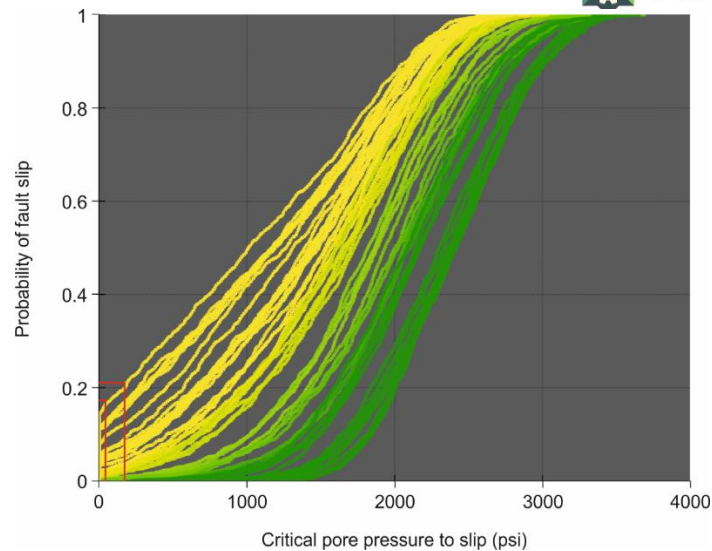


Figure 3.18. Cumulative distribution curves of the probability of slip of each fracture as a function of the critical pore pressure to trigger slip. 1 psi = 6.89 kPa.

#### 4 - Probabilistic Seismic Hazard Assessment

Analysis of the slip tendency and reactivation potential of pre-existing faults and hypothetical undetected fractures, suggest low probability of fault slip at the maximum allowed injection pressure of 16.5 MPa. Nevertheless, a probabilistic seismic hazard assessment was undertaken to understand if mitigation strategies are necessary to prevent large magnitude seismic events avoiding in this way the shut-down of the pilot site.

The probabilistic seismic hazard associated with CO<sub>2</sub> injection operations was based on linear seismic source models (i.e., faults) and areal sources (i.e., homogeneous distribution of the seismic sources in concentric rings) and is complemented by a ground motion prediction equation adapted to the national territory. Additionally, site conditions are accounted for using a geologically based VS<sub>30</sub> model developed specifically for mainland Portugal (Vilanova et al., 2018), which enables a spatially consistent estimation of local site amplification.

The main objective of this analysis is to calculate the peak ground acceleration with a 10% probability of exceedance over a 30-year horizon at any point within the study domain. The following assumptions were considered:

- Continuous CO<sub>2</sub> injection over 30 years at the injection point (see for example Figure 3.4 for location);
- The presence of known linear faults (see Figure 3.13 for a simplified conceptual model of the faults);
- The existence of areal seismic sources distributed in concentric rings (Figure 3.18);
- The Gutenberg-Richter law for magnitude distribution;
- A ground motion prediction equation calibrated for Portugal (Vilanova and Fonseca, 2007);
- Local site conditions derived from the VS<sub>30</sub> model of Vilanova et al. (2018).

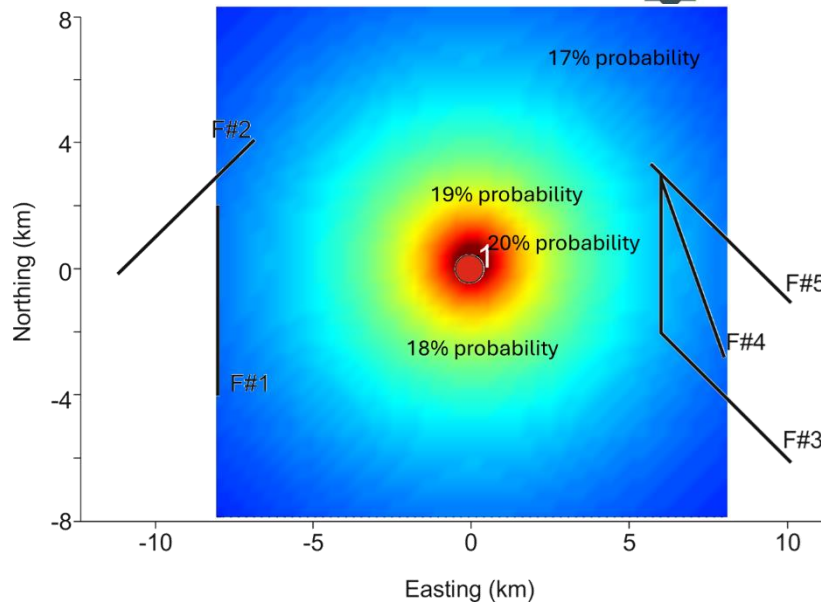


Figure 3.18. Source model and probabilities.

## 4.1 - Theoretical framework

### 4.1.1 - Characterization of seismic sources

Two types of sources were considered (Figure 3.18):

- Linear faults: Straight-line segments with known coordinates, representing active structures with seismic potential;
- Areal sources: Represented by concentric discs with a homogeneous probability of event occurrence, reflecting spatial uncertainty around the injection point.

### 4.1.2 - Gutenberg-Richter Law (recurrence law)

The magnitude distribution follows the equation:

$$\log_{10}N(M) = a - bM \quad (2)$$

with  $b = 1.3$ , a typical value for induced seismicity. Magnitudes range from 0 to 3 in increments of 0.5.

### 4.1.3 - Ground Motion Prediction Equation (GMPE)

Peak Ground Acceleration (PGA) is estimated using the simplified form of the empirical equation by Vilanova and Fonseca (2007):

$$\ln(PGA) = c_1 + c_2M + c_3 \ln(\sqrt{R^2 + h^2}) + \ln\left(\frac{760}{VS_{30}}\right) \quad (3)$$

where  $R$  (km) is the epicentral distance,  $h$  (km) is the mean depth (5 km in this study),  $VS_{30}$  (m/s) is the average shear-wave velocity in the top 30 meters. The coefficients  $c_1$ ,  $c_2$  and  $c_3$  are empirical coefficients and are equal to -1.715, 0.5 and -1.0, respectively.

$VS_{30}$  values are extracted from the Portugal-scale geologically based model developed by Vilanova et al. (2018), which provides a high-resolution representation of near-surface seismic velocities across

mainland Portugal (Figure 3.19). This model improves the accuracy of hazard predictions by incorporating realistic local site conditions into the Ground Motion Prediction Equation.

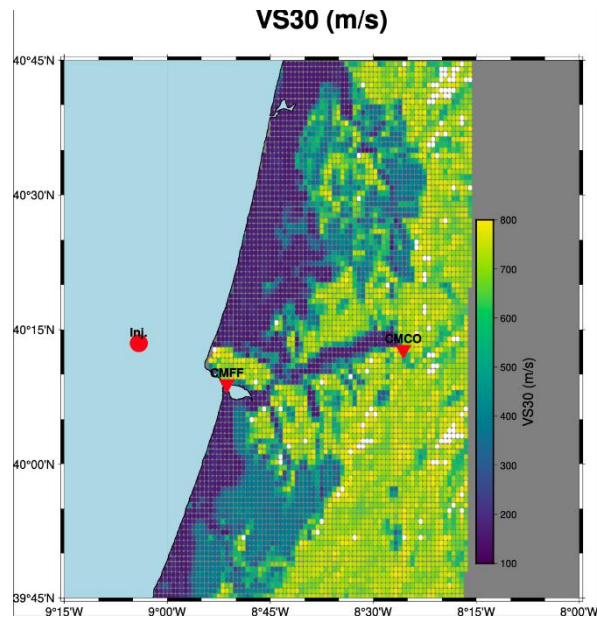


Figure 3.19.  $VS_{30}$  values (m/s) extracted from the Portugal based model developed by Vilanova et al. (2018). Inj- Injection site, CMFF (Figueira da Foz City Council) CMCO (Coimbra City Council).

### 3.1.4 - Probabilistic integration

For each source point:

- The distance to the observation point is calculated;
- Peak Ground Acceleration is estimated for each magnitude;
- The annual exceedance rate is computed for each Peak Ground Acceleration value;

The Peak Ground Acceleration with a 10% probability of exceedance over 30 years is obtained by solving:

$$P = 1 - e^{(-\lambda T)} \rightarrow \lambda = \frac{-\ln(1-P)}{T} \quad (4)$$

## 4.2 - Computational implementation

The model was implemented in Python, in a modular way:

- Definition of sources (i.e., faults and discs);
- Generation of discretized points for spatial integration;
- Application of the Ground Motion Prediction Equation to estimate Peak Ground Acceleration.
- Integration of exceedance rates by magnitude and location;
- Determination of the Peak Ground Acceleration and Intensity values satisfying the 10% probability in 30 years condition.

### 4.3 - Results

The Peak Ground Acceleration was calculated for a geographical grid, considering the combined contribution of all sources. For example, at the injection point, the result was Peak Ground Acceleration (PGA; Figure 3.20) and Intensities (MMI) values with 10% probability of exceedance in 30 years. This value represents the maximum expected ground acceleration with a 10% probability of being exceeded over the 30-year period. The Peak Ground Acceleration (PGA) and Intensity (MMI) values were calculated for two relevant urban centres: the centre of Figueira da Foz (CMFF) and the centre of the city of Coimbra (CMCOI) (Table 3.3).

Peak Ground Acceleration (PGA) and Intensity (MMI) values obtained for the study area range respectively, between 0.013-0.021g and 2.4 and 3.3, particularly in the most populated urban areas located closer to the offshore injection point. These values correspond to the “Very Weak” classification on the Modified Mercalli Intensity (MMI) scale, which indicates that the shaking is generally not felt, though it may be perceived by a few people at rest, especially on upper floors of buildings. No effects on structures are expected at these intensity levels.

Table 3.3. Seismic site relevant parameters.

Site	Latitude	Longitude	VS30 (m/s)	PGA (g)	Intensity (MMI)
CMFF	40.149	-8.855	456	0.021	2.4
CMCO	40.213	-8.427	516	0.013	3.3

### 5 - Possible Traffic Light System

Traffic Light Systems are commonly used as monitoring and decision-making approaches to mitigate the risk of undesired seismic events induced by human activities such as injection of CO<sub>2</sub> into geologic reservoirs (e.g., Mignan et al., 2017). Traffic Light Systems are based on a decision variable (earthquake magnitude, peak ground velocity, etc.) and a threshold value above which actions (e.g., stopping the injection or reducing production rates) must be taken (e.g., Mignan et al., 2017).

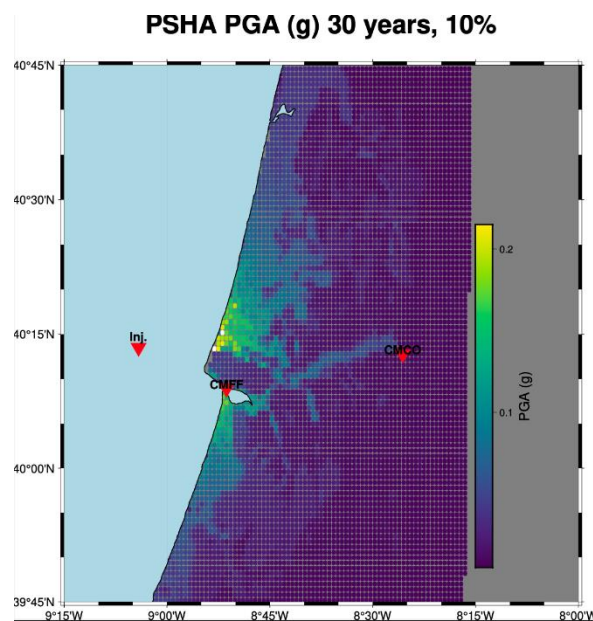


Figure 3.20. PGA values with 10% probability of exceedance in 30 years. Inj- Injection site, CMFF (Figueira da Foz City Council) CMCO (Coimbra City Council).

**A traffic-light system (TLS) should be defined before starting the injection and upon having improved the baseline of seismicity in the region.** As an example, Table 3.4 shows a possible TLS that rely on event magnitude, the Gutenberg–Richter *b*-value, and/or the peak ground acceleration (PGA) as complementary indicators.

- Under green conditions, seismicity is limited to background or microseismic events (e.g.  $M < 1.5$ ), the *b*-value remains high or stable ( $\approx 1.3$ ), and PGA is negligible; injection proceeds normally with routine monitoring;
- Yellow is triggered by an increase in maximum magnitude (e.g.  $M=1.5-2.5$ ), a systematic decrease in *b*-value over successive time windows, and/or moderate PGA; the recommended response is reduced injection rates and enhanced real-time monitoring;
- Red corresponds to the occurrence of an event above a predefined threshold (e.g.  $M \geq 2.5-3.0$ ), an abrupt drop in *b*-value, and/or PGA exceeding conservative ground-motion limits, prompting immediate suspension of injection and technical review.

This approach enables near-automatic operational decisions, provided continuous local monitoring and rapid data processing are in place, and avoids reliance on magnitude alone by incorporating both early-warning (*b*-value) and impact-related (PGA) metrics.

Table 3.4. Potential Traffic Light System for the prospect site.

Seismic event magnitude	Action	Comment
$M < 1.5$ , <i>b</i> -value high or stable and PGA negligible	<b>Go</b>	Injection proceeds as planned
$1.5 > M < 2.5$ , decrease in <i>b</i> -value and/or moderate PGA	<b>Caution</b>	Injection proceeds with caution, possibly at reduced rates. Monitoring is intensified
$M > 2.5$ , abrupt drop in <i>b</i> -value and/or PGA exceeding conservative ground-motion limits	<b>Stop</b>	Operator must suspend injection, reduce pressure and monitor seismicity and ground motion for any further events before potentially resuming

The magnitude and ground motion thresholds proposed for the Traffic Light System (TLS) constitute a project-specific operational risk management tool. They reflect international best practice and are suggested as a precautionary operational control mechanism consistent with the risk management principles of Directive 2009/31/EC. Final TLS operational thresholds would be defined in agreement with the competent authority as part of any future commercial-scale permitting process.

## 6 - Conclusions

Geologic storage of CO<sub>2</sub> is a promising approach to help reducing greenhouse gas emissions, but injecting fluids within geologic reservoirs can change their *in-situ* conditions and lead to induced seismicity. Nevertheless, the risk is generally low if the site is properly selected, and the injection operations and monitoring are correctly made.

This study had the objective of analysing the natural seismicity hazard of a potential CO<sub>2</sub> storage site located in the offshore of Figueira da Foz (Portugal) and evaluate the risk of induced seismicity considering the planned injection rate (15 kg/s) and injection period (30 years).

The results suggest that, while at a regional scale (10000 km<sup>2</sup>) the probability of occurrence of natural events with magnitudes greater than 2.0 and 3.0 which are the most common recorded earthquakes is 100% within the next 100 years, at a more local scale surrounding the injection well (400 km<sup>2</sup>), these probabilities decrease to 80% and 20%, respectively. Such results suggest that there is a very low probability of events of magnitude greater than 3.0 to occur as a consequence of CO<sub>2</sub> injection. Furthermore, analyses of the slip tendency of pre-existing faults suggest that at the planned injection rate of 15 L/s during a 30-year injection period, the probability of these fractures to slip is about 25%. The probability of faults or fractures located in close proximity of the injection point to slip of 30%. This suggests that the probability of inducing seismic events as a consequence of carbon injection within the reservoir is very low. Nevertheless, a probabilistic seismic hazard assessment was carried out considering these probabilities and a methodology that was put forward in the context of this study and revealed Peak Ground Acceleration (PGA) and Intensity (MMI) values ranging, respectively, between 0.013-0.021g and 2.4 and 3.3. These values correspond to the “Very Weak” classification on the Modified Mercalli Intensity (MMI) scale, which indicates that the shaking is generally not felt, though it may be perceived by a few people at rest, especially on upper floors of buildings. No effects on structures are expected at these intensity levels. Therefore, all the analyses carried out suggest that the prospect site in the offshore of Figueira da Foz is safe for CO<sub>2</sub> storage. Furthermore, a potential Traffic Light System was put forward considering the results of this study to help defining guidelines for CO<sub>2</sub> injection operations at the study site.

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