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CO_2 Geological Storage: Digital tools for Screening & Maturation of Marketable Volumes

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Summary

A user-friendly App has been developed to carry out assessments of suitable geological sites for permanent storage of CO_2.
Relevant criteria covering the full TECOP spectrum are incorporated.
The App can be linked to a code that is used to quantify storage resources reliably and quickly, associated to a sensible notional development plan.
This allows the highest chance of developing into a marketable Storage Capacity, through commercially viable storage development plans.

Introduction

Many organizations and governments have committed to Net Zero GHG emissions by 2050 with more to follow suit after the recent IPCC report and the agreements arising from COP-26.

Business models driving Net Zero will be enabled by permanent CO_2 storage in adequate geological storage sites.

Site selection may be different, depending on the business model. Depleted oil/gas fields are usually accessible, data rich with existing infrastructure; however, they may be challenged in terms of storage resources and scalability, as well as containment risks. Saline aquifers comprise an extensive portfolio of crucial Gigaton scale CO_2 storage options, though they may pose challenges to characterisation through data gaps and uncertainties.

Estimations of storage resources with the highest chance to develop to commercially viable volumes require clear technical guidelines. To ensure safe and permanent containment, 3 technically robust core activities are required.

Storage characterization & Storage resources estimation, including scalability considerations.

Containment risk assessment: Considering geological and anthropogenic (wells) leak paths.

Costs & Risk mitigation: Identifying the correct technologies to ensure permanent containment and storage effectiveness.

Proposed Method

Aiming to support viable projects within an optimal timeline, there are 6 key requirements (Fig.1 - top) that can be used to rank prospective geological storage sites, either if they are depleted fields or saline aquifers. These requirements are translated into clear criteria (Fig.1 – bottom) that determine what available data is needed to carry out an adequate risk assessment and estimation of storage resources, but also any data acquisition needs.

The CO_2 Storage Screening & Maturation App

A user-friendly App has been developed to carry out assessments of suitable geological storage sites. The App would not replace a detailed site-specific assessment towards a CO_2 storage verification or certification, but it can be useful to establish a first pass idea of the maturity/confidence of a particular candidate storage site.

The App helps define Technical requirements for storage suitability and maturity level, but also other requirements within the "ECOP" spectrum.

Based on specific criteria linked to the 6 main requirements (Fig.1), the App provides an Objective Classification in terms of Qualitative Risk and Level of Maturity/Confidence (Fig. 2).

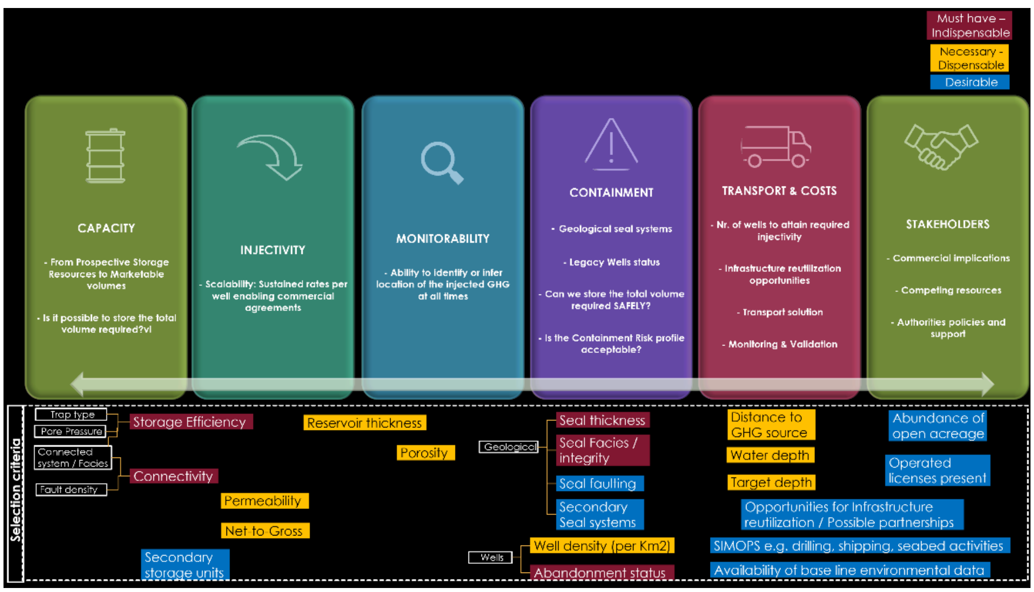

Figure 1 *Requirements and specific criteria for a successful GHG/CO_2 storage site*

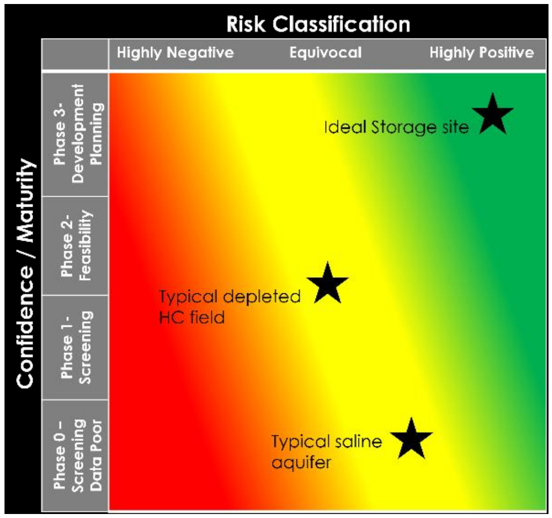

Figure 2 *Classification system implemented in our GHG/CO2 Storage screening App*

The Monitorability question

One key Screening criterion to take into consideration is **Monitorability** using active Seismic methods.

Active seismic is not necessarily the main tool to constantly deploy in the selected CO_2 storage site. However, it is not uncommon to include cost-efficient techniques like 2DHR or DAS-VSP to be deployed during injection with a determined frequency, and also a final 3D seismic survey as part of the hand-over criteria once injection operations come to an end.

This is why the screening App is able to carry out on-the-fly Gassmann substitution for a user defined CO_2 Saturation, injected in a brine-saturated reservoir with a user-defined composition of Quartz and/or Calcite, which provides an assessment of the expected Acoustic Impedance difference (percentage) VS. Porosity (Fig. 3). The result provides evidence of detectability of the CO_2 plume using active seismic methods, assuming the reservoir thickness is at least ~20m (resolvable with standard surface active seismic).

As a general rule-of-thumb, for storage sites < 4 Km deep and assuming nRMS < 15%, detectability values of > 20% AI difference are quite standard for any time lapse active seismic response, even 2D or DAS-VSP.

The proposed tool can therefore help define what is a reasonable porosity threshold of Monitorability for a specific CO_2 storage site.

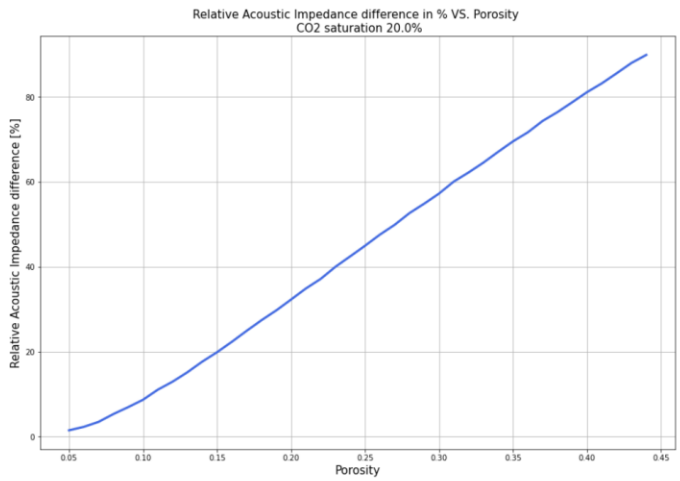

Figure 3 *Example of a 20% CO_2 saturation in an initially brine saturated sandstone with mainly quarzitic matrix, a porosity of 15% would can be considered a good threshold to confidently detect (20% AI difference) the injected CO_2 with active seismic methods*

A Novel tool to effectively quantify CO_2 storage resources

Fundamental missteps have been identified that frequently occur when petroleum professionals have attempted to quantify CO_2 storage resources.

The tool underlines the importance of site-specific transient effects in Pressures, caprock integrity, rock and fluid Compressibility, Temperature, CO_2 density, stress regime, among others, over the static pore space analysis often used by petroleum professionals when CO_2 storage resources are reported.

The cartoon in Fig. 4 depicts how a Maximum Pressure (Pmax) is computed for a saline aquifer. Pmax is not only dependant on the initial Pressure (Pini) at the injection point, but most importantly it is defined by the weakest (shallowest) zone within the connected volume. This can be the geological crest (caprock), a bounding fault, or the plug within a legacy well.

This Pressure “space” defined by the different between Initial Pressure (Pini) and Maximum Pressure (Pmax), which is directly linked to the Storage Efficiency of the saline aquifer or the Storage Coefficient of a depleted field. As expected, in case of depletion, either created by hydraulic connectivity with (nearby) hydrocarbon fields, or created by water producers, the Pressure “space” allows more CO_2 to be stored, improving the Storage Efficiency.

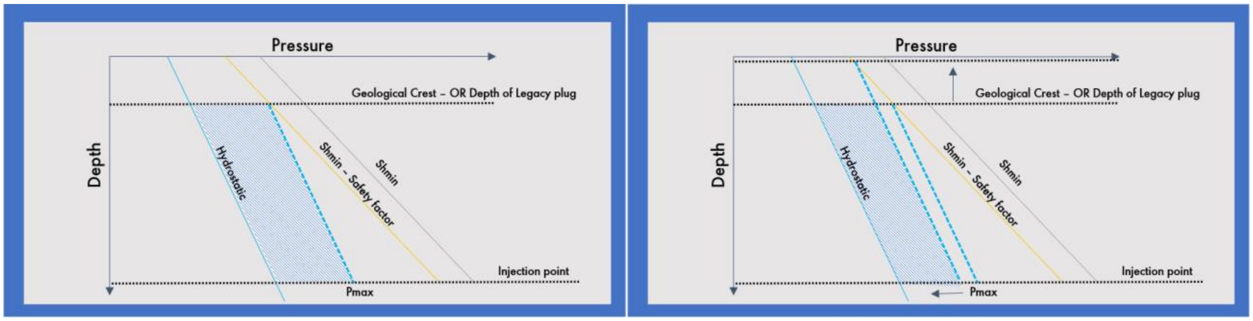

Figure 4 *Left: Maximum Pressure defined by the geological crest, or a legacy well plug, whichever is shallowest. Right: Effect of a shallower constraint directly lowering the Maximum Pressure, and hence the storage resources*

Hence, with the relevant input, the App can be linked to a code used to adequately and quickly account for all dynamic aspects of CO_2 injection into saline aquifers or depleted fields, which allows to estimate realistic CO_2 storage resources for a particular notional development plan (Fig. 5). This allows the highest chance for the identified storage resources to mature further into marketable volumes (Capacity), following the SPE SRMS system (2017).

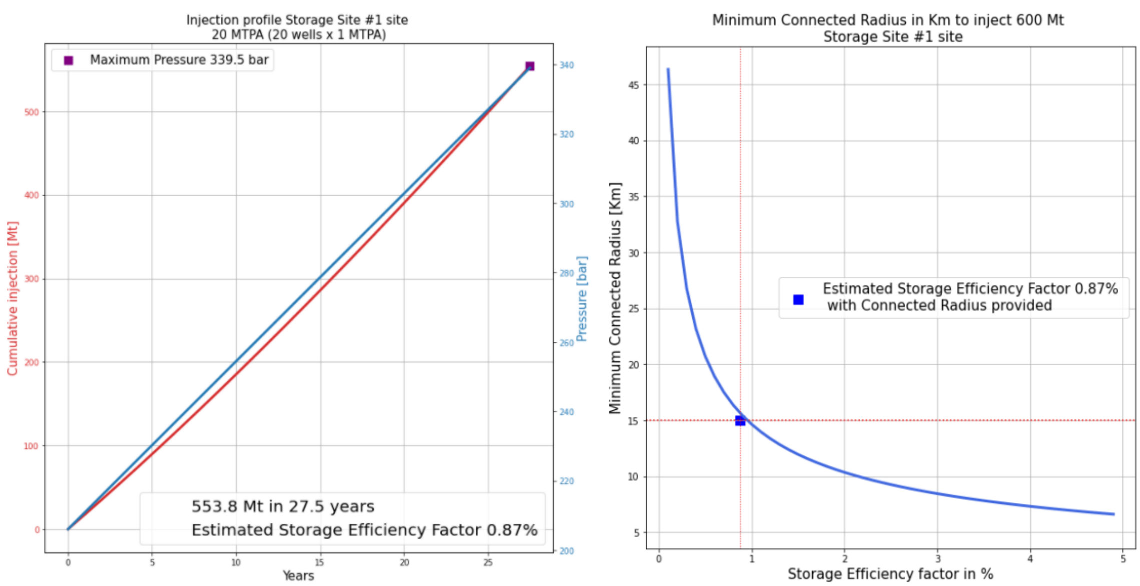

Figure 5 *Example of an estimation of CO_2 storage resources (Left) accounting for transient effects in Pressures, caprock integrity, rock and fluid Compressibility, Temperature, CO_2 density, stress regime, among others. On the Right, a Minimum Connected Area is estimated for a user-provided required CO_2 storage Capacity and impact of assumed Storage Efficiency Factors*

The graph created by Hoffman et al. (2015) – Fig. 6 (Left), has also been incorporated into the tool, allowing to directly use analogue public information to support a prognosis for the expected injectivity in MTPA for a prospective storage site. Provided relevant data such as thickness, Net-to-Gross and Permeabilities, the user can define a notional development plan in terms of number of wells and injectivity per well.

Based on the adequate input, the tool estimates the Maximum allowable Pressure in the “tank”, which is used to calculate the Maximum Cumulative Injection in Megatons, unless pore space is created through (water) production, allowing additional Capacity. The resulting Storage Efficiency factor is also estimated and plotted against the Connectivity curve (Fig. 5 – Right) for quality control purposes.

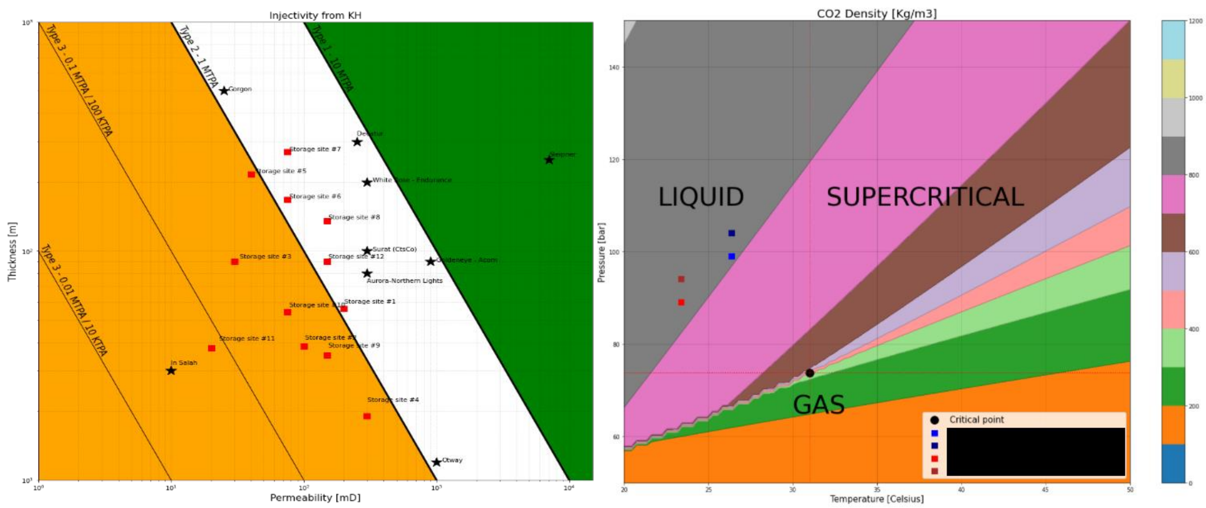

Figure 6 Left: Net Thickness VS. Permeability plot as per Hoffman et al. (2015). Right: CO_2 Density values on Kg/m^3 depending on Pressure and Temperature (Span & Wagner, 1996)

In summary, based on the input below:

- Estimation of the Hydraulically Connected Area,
- Average Gross reservoir thickness,
- Average Porosity & NtG,
- Hydrostatic and Temperature gradients,
- Estimated Minimum Horizontal Stress at the crest (Shmin),
- Notional development plan: assumed injectivity (based on Fig.6 - Left) times # wells.

The tool computes:

- Rock Compressibility as per Hall (1953),
- Fluids Compressibility (which decreases gradually as Pressure increases) as per Brill & Beggs (1978),

- CO_2 density - Pressure and Temperature dependant, as defined by the CO_2 Equations of State (Span & Wagner, 1996 – Fig. 6-Right) or valid approximations (such as Ouyang, 2011),
- Maximum allowable Pressure in the "tank",
- Maximum Cumulative Injection – Storage Resources in Mt.

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