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MEMOIRE

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Option : Production professionnel

Présenté Par :

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-Thème-

ETUDE DES PROPRIETES FONDAMENTLES DU RESERVOIR POUR UN STOCKAGE SECURISE DU CO_2

Une méthode de récupération améliorée EOR et contribution à la lutte contre les gaz à effet de serre

Soutenue le : 22/ 06/ 2021 devant la commission d'examen

Jury :

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THESIS

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-Title -

STUDY OF FUNDAMENTAL RESERVOIR PROPERTIES FOR SECURE CO_2 STORAG IN HYDROCABON FIELDS

An improved enhanced oil recovery method and contribution to fight against greenhouse gases

Presented on: 22/06/2021 in front of the jury:

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Dedicated to my beloved parents…

Thank you for instilling in me the virtues of

Perseverance and commitment and

Encouraging me to strive for excellence.

To Chaima & Hayat, for being for me.

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Dedicated to my loving parents Djihad and

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push for tenacity, ring in my ears

To my sisters Nour, Djoumana and my brother Rami

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Abstract:

Nowadays, with the increasing energy demand and declining oil field productivity, it became mandatory to increase focus on the improvement of oil recovery from mature hydrocarbon fields. In addition, continuous and excessive emission of carbon dioxide from fossil fuel combustion or other industrial sources to the atmosphere has led the world to witness extreme climatic change. The main aim of this project is:

- An in-depth study of key reservoir properties controlling the long-term security of CO_2-EOR and sequestration;
- Demonstrating the importance of different trapping mechanisms and their security levels;
- A study of the crucial impact of maintaining storage sites integrity before, during and post injection on the security of every CCS project.

ملخص:

نظرا للطلب المتزايد على الطاقة وانخفاض إنتاجية حقول النفط، أصبح من الضروري التركيز على تحسين استخراج النفط من الحقول المستنفذة. في المقابل، الانبعاث المستمر والمفرط لثاني أكسيد الكربون (CO_2) من احتراق الوقود الأحفوري أو المصادر الصناعية الأخرى في الغلاف الجوي قد أدى الى تغيير مناخي شديد .الهدف من هذه المذكرة هو:

- دراسة معمقة لخصائص المكمن التي تتحكم في مدى فاعلية تخزين ثاني أكسيد الكربون وعزله في المكامن الجيولوجية العميقة;
- توضيح أهمية آليات التخزين المختلفة ومدى امانها.
- دراسة تأثير "الحفاظ على سلامة مواقع التخزين" قبل، أثناء وبعد حقن ثنائي اكسيد الكربون على مشاريع تخزين ثاني أكسيد الكربون.

Résumé :

Aujourd’hui, la demande croissante énergétique et la baisse de la productivité des champs pétrolifères, il est devenu obligatoire de se concentrer sur l'amélioration de la récupération du pétrole des champs d'hydrocarbures matures. Ceci est rencontré en sachant que l'émission continue et excessive de dioxyde de carbone provenant de la combustion de combustibles fossiles ou d'autres sources industrielles dans l'atmosphère a conduit le monde à des changements climatiques extrêmes. L'objectif principal de ce projet est :

- Une étude approfondie de l’effet de propriétés fondamentales du réservoir sur l’efficacité et la sécurité à long terme de stockage de gaz carbonique et CO_2-EOR ;
- Démontrer l'importance des différents mécanismes de piégeage et leurs niveaux de sécurité ;
- Une étude de l'impact crucial du « maintien de l'intégrité des sites de stockage » avant,

pendant et après l’injection sur la sécurité de tout projet de CSC.

Keywords:

CO_2 storage, greenhouse gases effect, EOR+ by storing CO_2, reservoir properties for secure CO_2 storage.

Table of content:

Chapter III: Enhanced oil recovery and sequestration (EOR+) by injecting miscible CO_2 gas.

Chapter IV: Study of In Salah CCS project (Krechba field)

List of figures :

Chapter I: carbon dioxide storage overview and applications.

Chapter II: Reservoir properties and CO_2 underground geological storage.

Chapter III: Enhanced oil recovery and sequestration (EOR+) by injecting miscible CO_2 gas.

Chapter IV: Study of In Salah CCS project (Krechba field).

List of tables :

Abbreviations:

ARI	Advanced Resources International
CCS	Carbon Capture and Storage
CO2	Carbon Dioxide
DSF	Deep Saline Formations
EC	Economic Efficiency Factor
ECBM	Enhanced Coal Bed Methane recovery
ED	Connected Volume Factor
EOR	Enhanced Oi Recovery
EOR+	Simultaneous CO_2-EOR and Storage
EPS	Microscopic Displacement Efficiency
ES	Sweep Efficiency
GAGD	Gas Assisted Gravity Drainage
GHG	Greenhouse Gases
IEA	International Energy Agency
IEAGHG	International Energy Agency Greenhouse Gas R&D Program
IPCC	Intergovernmental Panel on Climate Change
LGT	Linear Gradient Theory
LSIPs	Large-Scale Integrated Carbon Capture and Storage Projects
MMP	Minimum Miscibility Pressure
MMV	Monitoring, Management, and Verification
MOC	Method of Characteristics
MVA	Monitoring, Verification, and Accounting
$MtCO_2$	Million metric Tons Of CO_2
RBA	Rising Bubble Apparatus
RF	Recovery Factor
OOIP	Oil Originally in Place
WAG	Water Alternating Gas

Introduction:

Since the beginning of industrial revolution in 18th century until to date, the concentration of greenhouse gases in the atmosphere has a trend of continuous growth. It is known that a CO_2 emission has the largest impact on the climate change, with a share of 80% in the total emission of greenhouse gases.

One of the recent solutions for carbonic gas emission mitigation is CO_2 geological storage. This option includes capture of anthropogenic gases, its transportation and injection in different types of geological formations such as: depleted oil and gas reservoirs, saline formations, unmined coal beds, injection in partially depleted oil reservoirs for enhanced oil recovery (EOR–CO_2 method), and others (salt caverns, basalt formations, shales).

A successful carbon dioxide storage project would involve accurate site selection, characterization (storage capacity estimation, plume modeling) and monitoring to avoid the risks of leakages through seals, faults and abandoned wells. The main aim of this thesis is to study the fundamental reservoir properties for secure co_2 storage in hydrocarbon fields, to achieve the main objective of the study; this research divided into three chapters.

The first chapter of this thesis reviews the concept of the carbon dioxide storage and its contribution to reduce greenhouse gas emissions from the continued use of fossil fuels.

The second chapter examines the different trapping mechanisms that leading the storage of CO2 to keep it from escaping back into the atmosphere. This review brings out the principal characteristics of controlling both the Capacity and the security of CO_2 sequestration projects.

The third chapter present the application of CO_2 in EOR, that aims to extending the production life of oilfield through EOR (Enhanced Oil Recovery), employing a captured CO_2.

The fourth chapter presents the results of a feasibility study aimed at explore the factors that led to the CO_2 leakage in In Salah CSS project and some recommendations.

Chapter I:

Carbon dioxide storage overview and applications.

1. Introduction:

Carbon dioxide is a greenhouse gas that occurs naturally in the atmosphere. Human activities, are significantly increasing its concentration in the atmosphere, thus contributing to Earth's global warming. One technique that could limit CO2 emissions is carbon dioxide capture and storage (CCS). The first chapter states the meaning of CCS, then discusses carbon contribution to fight against greenhouses gas, the chapter closes by presenting some existing and planned projects and its application in Algeria.

2. What is carbon dioxide storage?

Carbon dioxide (CO_2) capture and storage (CCS) is a process consisting of the separation of CO_2 from industrial and energy-related sources, transport to a storage location and long-term isolation from the atmosphere. [22]

Injection into oil, gas, and water-bearing geological formations is widely regarded as the front running option for CO_2 storage and is the only option that has so far been applied on a commercial scale. The readiness of this option for commercial deployment is due to the use of site characterization, injection, and monitoring technologies. [45]

3. CCS contribution to fight against greenhouse gases and uses for EOR purposes:

3.1 CCS to fight against greenhouse gases:

Other mitigation options include energy efficiency improvements, the switch to less carbon-intensive fuels, nuclear power, renewable energy sources, enhancement of biological sinks, and reduction of non-CO_2 greenhouse gas emissions. CCS has the potential to reduce overall mitigation costs and increase flexibility in achieving greenhouse gas emission reductions. The widespread application of CCS would depend on technical maturity, costs, overall potential, diffusion and transfer of the technology to developing countries and their capacity to apply the technology, regulatory aspects, environmental issues and public perception.

Available technology captures about 85–95% of the CO_2 processed in a capture plant. A power plant equipped with a CCS system (with access to geological or ocean storage) would need roughly 10–40%4 more energy than a plant of equivalent output without CCS, of which most is for capture and compression. For secure storage, the net result is that a power plant with

CCS could reduce CO_2 emissions to the atmosphere by approximately 80–90% compared to a plant without CCS (see figure I.1) [22] [38]

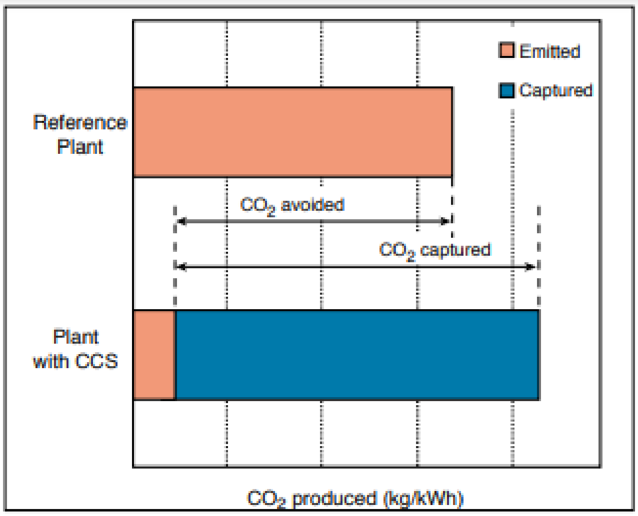

Figure I.1: CO_2 capture and storage from power plants.[1]

3.2 CCS for enhanced oil recovery:

As part of the CO_2-EOR process, CO_2 is injected into an oil-bearing stratum under high Pressure. Oil displacement by CO_2 injection relies on the phase behavior of the mixtures of gas and the oil, which are strongly dependent on reservoir temperature, pressure and oil Composition. [8]

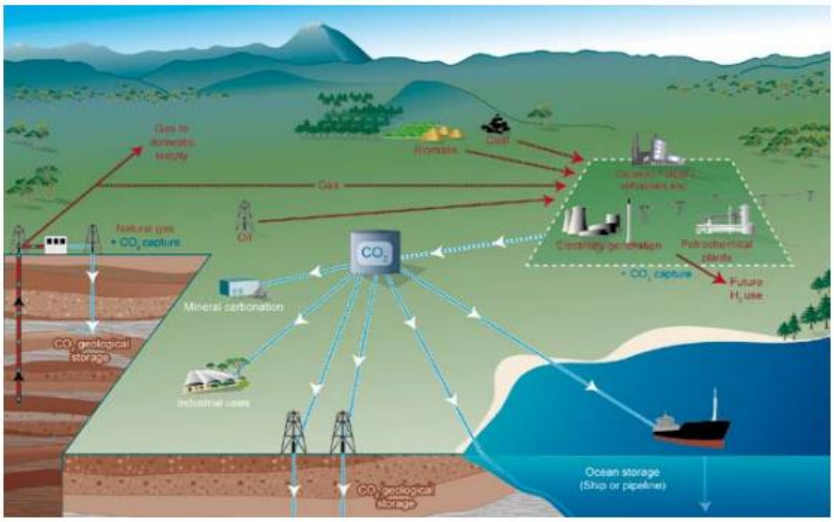

Figure I.2: Schematic diagram of possible CCS systems showing the sources for which CCS might be relevant, transport of CO_2 and storage options [1].

4. Current status of CO_2 capture and storage technologies:

4.1 CO_2 capture technologies :

There are different types of CO_2 capture systems: post combustion, pre-combustion and oxyfuel combustion (Figure I.4). The concentration of CO_2 in the gas stream, the pressure of the gas stream and the fuel type (solid or gas) are important factors in selecting the capture system.

Post-combustion capture of CO_2 in power plants is economically feasible under specific conditions. It is used to capture CO_2 from part of the flue gases from a number of existing power plants. Separation of CO_2 in the natural gas processing industry.

The technology required for pre-combustion capture is widely applied in fertilizer manufacturing and in hydrogen production. Although the initial fuel conversion steps of pre-combustion are more elaborate and costly, the higher concentrations of CO_2 in the gas stream and the higher pressure make the separation easier.

Oxyfuel combustion is in the demonstration phase and uses high purity oxygen. This results in high CO_2 concentrations in the gas stream and, hence, in easier separation of CO_2 and in increased energy requirements in the separation of oxygen from air.

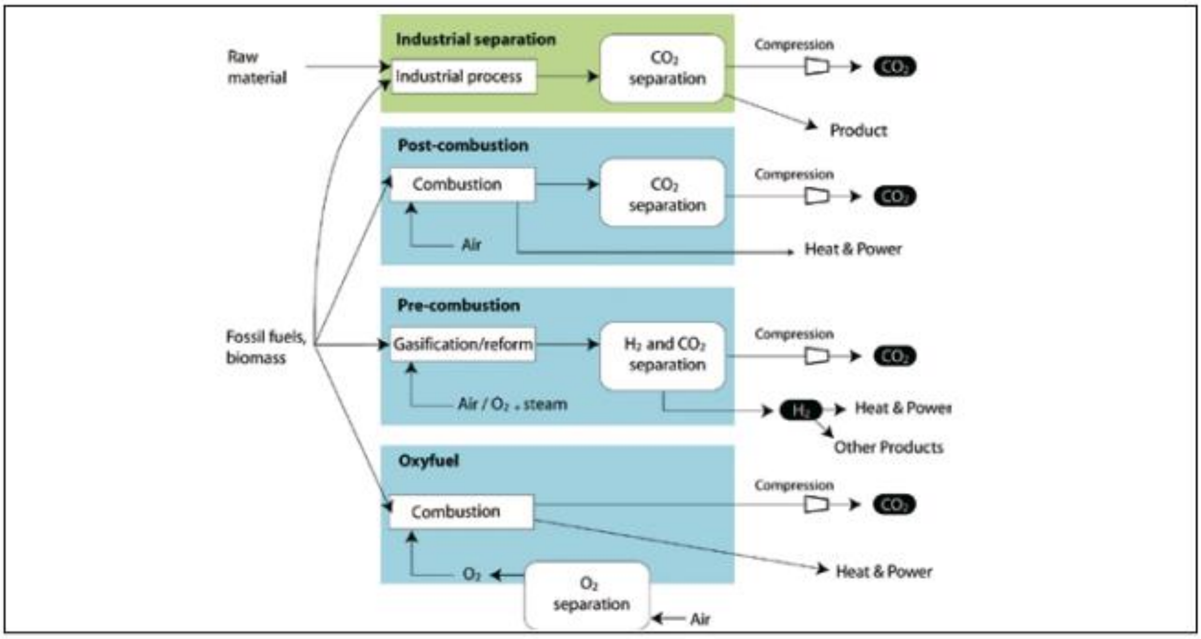

Figure I.3: Schematic representation **of** carbon capture systems.[1]

4.2 CO_2 Storage options :

Storage of CO_2 in deep, onshore or offshore geological formations uses many of the same technologies that have been developed by the oil and gas industry and has been proven to be economically feasible under specific conditions for oil and gas fields and saline formations, but not yet for storage in unmineable coal beds (see Figure I.5).

Besides the underground geological storage (our targeted study), there are other options for $C0_2$ storage such as ocean storage either by dissolving it in water or injecting it in the sea floor using an offshore platform, the second option is reactions of carbons dioxide, The technology is currently in the research stage. [22]

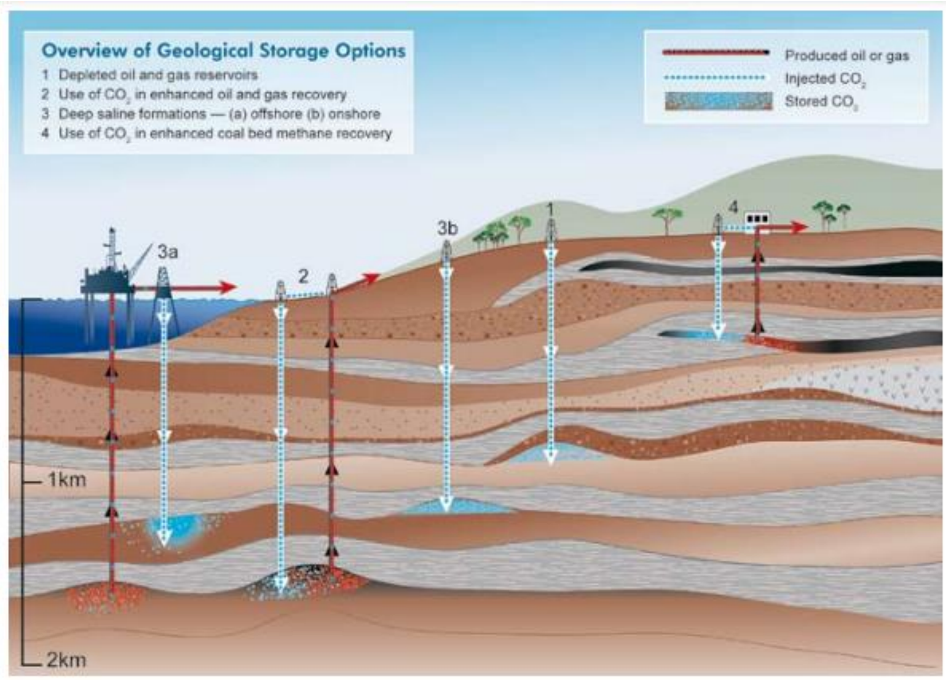

Figure I.4: Overview of geological storage options [1].

5. Existing and planned CO_2 storage projects:

The Global CCS Institute, a think tank, announced that ten large-scale carbon capture and storage (CCS) facilities were verified and added to its database. “There are now 51 CCS facilities globally 19 in operation, four under construction, and 28 in various stages of development with an estimated combined capture capacity of 96 million tonnes of CO_2 per annum.

A number of pilot and commercial CO_2 storage projects are under way or proposed To date, some of actual or planned commercial projects are associated with major gas production facilities that have gas streams containing CO_2 in the range of 10–15% by volume, such as Sleipner in the North Sea, Snohvit in the Barents Sea, In Salah in Algeria and Gorgon in Australia, as well as the acid gas injection projects in Canada and the United States. At the Sleipner Project, operated by Statoil, more than 7 MtCO_2 has been injected into a deep subsea saline formation since 1996.

At the In Salah Gas Field in Algeria, Sonatrach, BP and Statoil inject CO_2 stripped from natural gas into the gas reservoir outside the boundaries of the gas field. Statoil is planning another project in the Barents Sea (concept phase), where CO_2 from the Snohvit field will be stripped from the gas and injected into a geological formation below the gas field. Chevron is producing gas from the Gorgon field off Western Australia, containing approximately 14% CO_2. The CO_2 is injected into the Dupuy Formation at Barrow Island. In the Netherlands, CO_2 is being injected at pilot scale into the almost depleted K12-B offshore gas field. Forty-four CO_2 -rich acid gas injection projects are currently operating in Western Canada, ongoing since the early 1990s. Although they are mostly small scale, they provide important examples of effectively managing injection of CO_2 and hazardous gases such as H_2S. Eight of these new major CCS projects are located in United States and two respectively in the United Kingdom and the United Arab Emirates.[22] [2]

6. Application of CO_2 storage in Algeria:

The In Salah Gas Project, a joint venture among Sonatrach, BP and Statoil located in the central Saharan region of Algeria, is the world's first large-scale CO_2 storage project in a gas reservoir The Krechba Field at In Salah produces natural gas containing up to 10% CO_2 from several geological reservoirs and delivers it to markets in Europe, after processing and stripping the CO_2 to meet commercial specifications. The project involves re-injecting the CO_2 into a sandstone reservoir at a depth of 1800 m and storing up to 1.2 Mt CO_2 per year. Carbon dioxide injection started in April 2004 and, over the life of the project, it is estimated that 17 MtCO_2 will be geologically stored. The project consists of four production and three injection wells (Figure I.6). Long-reach (up to 1.5 km) horizontal wells are used to inject CO_2 into the 5-mD permeability reservoir.

The Krechba Field is a relatively simple anticline. Carbon dioxide injection takes place down-dip from the gas/water contact in the gas-bearing reservoir. The injected CO_2 is expected to eventually migrate into the area of the current gas field after depletion of the gas zone. The field has been mapped with three-dimensional seismic and well data from the field. Deep faults have been mapped, but at shallower levels, the structure is unfaulted. The storage target in the reservoir interval therefore carries minimal structural uncertainty or risk. The top seal is a thick succession of mudstones up to 950 m. A preliminary risk assessment of CO_2 storage integrity has been carried out and baseline data acquired. Processes that could result in CO_2 migration from the injection interval have been quantified and a monitoring program is planned involving a range of technologies, including noble gas tracers, pressure surveys, tomography, gravity baseline studies, microbiological studies, four-dimensional seismic and geomechanical monitoring.[22]

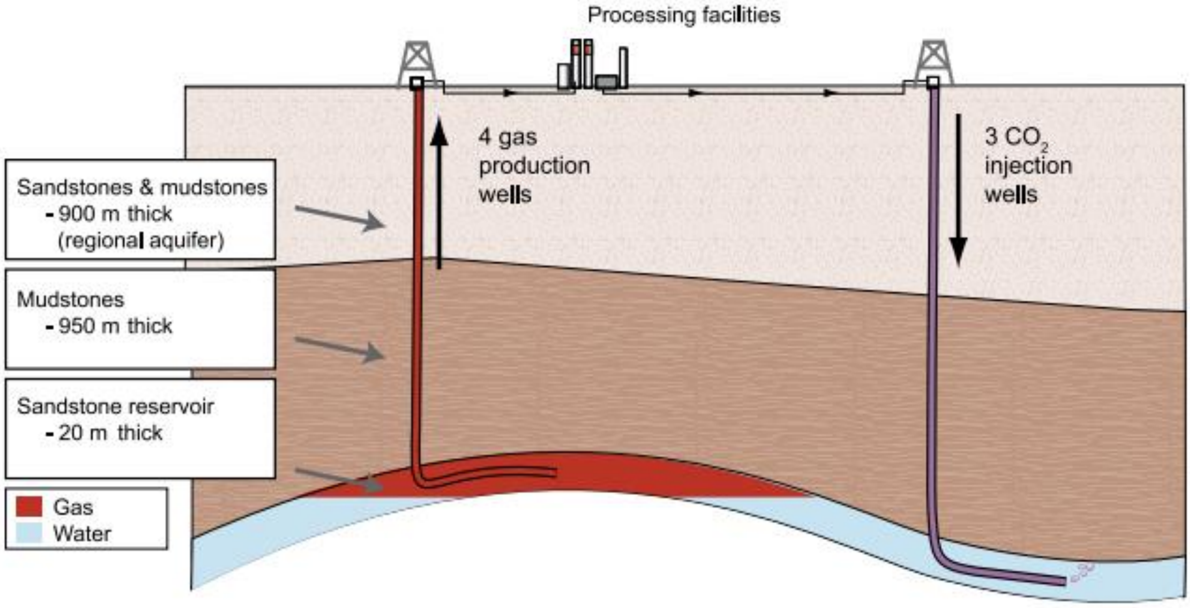

Figure I.5 Schematic of the In Salah Gas Project, Algeria.

7. Conclusion:

CO2 capture and storage are technologically feasible and could play a significant role in reducing greenhouse gas emissions over the course of this century. The In Salah Gas Project, is the world's first large-scale CO2 storage project in a gas reservoir The Krechba Field.

Chapter II:

Reservoir properties and CO_2 underground geological storage.

1. Introduction:

The role of CCS as an effective climate mitigation technology depends on our ability to securely store large volumes of carbon dioxide (CO_2) in geological formations for thousands of years. We know that oil and gas have been contained in underground reservoirs for much longer periods of time. Some the Current experiences from large-scale injection cases, and the CO_2-EOR projects, has confirmed that CO_2 can also be stored securely. Various trapping mechanisms work together in the subsurface to keep it from escaping back into the atmosphere. However, injected CO_2 may leak through natural or man-made pathways, causing effects on drinking water and marine ecosystems. The total potential leakage and its extent depends on a number of parameters to be specified in this chapter. Adequate geological, geophysical and geomechanical assessment of a potential CO_2 injection site is thus the key to safe operations.

This chapter reveals a number of parameters controlling both the Capacity and the security of CO_2 sequestration projects. [54] (Edited)

2. CO_2 storage mechanisms:

2.1 Trapping mechanisms in geological formation:

2.1.1 Hydrodynamic trapping:

Hydrodynamic trapping refers to that CO_2 is trapped as supercritical fluid or gas under a low-permeability caprock. Carbon dioxide, being less dense than the formation fluid, will rise buoyantly until it encounters a caprock that has a capillary entry pressure greater than the buoyancy or hydrodynamic force. CO_2 will accumulate in such a structural or stratigraphic feature that has both vertical and lateral seals. Trapping by such a seal is called structural or stratigraphic trapping, or hydrodynamic trapping. This mechanism is very important in that it is a prerequisite for any storage site because it prevents the leakage of CO_2 through the caprock during the time required for other trapping mechanisms to come into effect [46].

For such trapping mechanisms, the trapping efficiency is determined by the structure of the sedimentary basins, which have an intricate plumbing system defined by the location of high and low permeability strata that control the flow of fluids throughout the basin. There are numerous variations of structural and stratigraphic traps, or combinations of both structural and stratigraphic traps that can be physical traps for geological CO_2 storage. Common structural traps include anticlinal folds or sealed fault blocks (Figure II.1). CO_2 can fill to the spill point until the breakthrough pressure is exceeded.

Structural or stratigraphic traps are mostly found in reservoirs that have held oil and gas for millions of years. In these reservoirs, storage capacity mainly depends on the volume of pore space. Hydrodynamic trapping has been recognized in saline aquifers of sedimentary basins that have extremely slow flow rates.

A volume of carbon dioxide injected into a deep hydrodynamic trap may take millions of years to travel by buoyancy forces up dip to reach the surface before it leaks back into the atmosphere. For these traps, storage capacity is affected by both the volume of pore space and the reservoir permeability [56]. CO_2 sequestration by this physical trapping mechanism depends greatly on the sealing capacity of caprock, making it a big challenge for site selection [29].

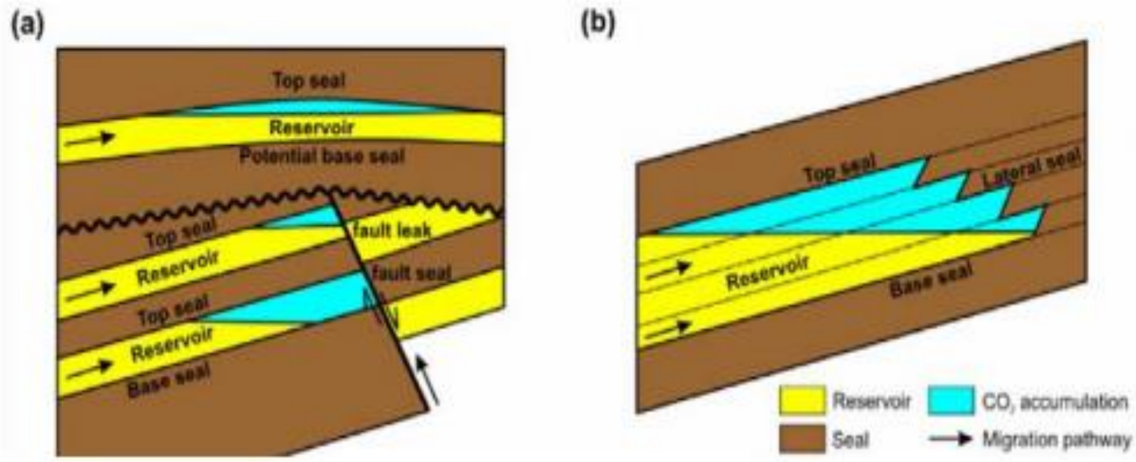

Figure II.1: Examples of (a) structural and (b) stratigraphic traps for CO_2 [30].

2.1.2 Residual trapping:

This phase of trapping happens very quickly as the porous rock acts like a tight, rigid sponge. When CO_2 is injected into the reservoir, it first displaces brine in a co-current fashion. But when the injection is stopped, due to the density difference between CO_2 and brine, the fluids flow in a counter-current fashion so that CO_2 migrates up towards and the brine flows downwards. Thus, the wetting phase (brine) enters the pores by less-wetting phase (CO_2). In such a process, the brine displaces CO_2, leading to a significant saturation of CO_2 becoming trapped in small clusters of pores see (Figure II.2). The disconnected CO_2 is then trapped as an immobile phase. This trapping mechanism is called the residual or capillary trapping [52].

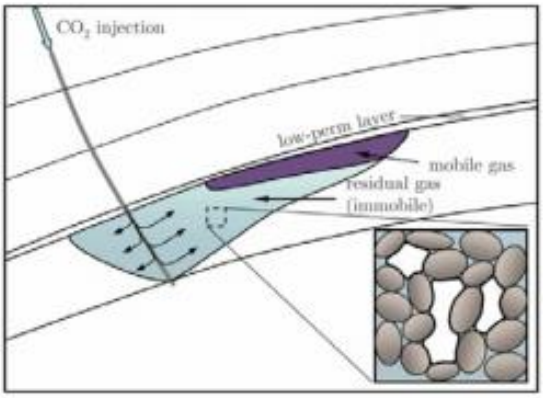

Figure II.2: Schematic of the trail of residual CO_2 that is left behind because of snap-off as the plume migrates upward during the post-injection period [44].

2.1.3 Solubility trapping:

Solubility trapping refer to dissolution of CO_2 in formation fluid. CO_2 would migrate upwards to the interface between reservoir and caprock after injection and then spread laterally under caprock as a separate phase. When CO_2 contacts with the ambient formation brine and hydrocarbon, mass transfer occurs with CO_2 dissolving into the brine until an equilibrium state is reached. The solubility of CO_2 in water is dependent on the salinity, pressure and temperature of the formation water. At the interface of free gas phase and formation water, CO_2 dissolves into water by molecular diffusion. The water in contact with CO_2 will be saturated with CO_2 and a concentration gradient of CO_2 would establish spatially. This process is very slow because the molecular diffusion coefficient is very small. It will take thousands of years for CO_2 to be completely dissolved in brine 15].

When diffusive CO_2 dissolves in brine, it slightly increases the brine density. The dissolution would increase the density of brine up to approximately 1% compared with the original formation brine.

The heavier brine on the top of aquifer would flow downward due to gravity. Such convection enhances the mixing of CO_2 and brine and stimulates the diffusion process, following more dissolution of CO_2. The dissolution reduces CO_2 upward mitigation as well as increases the storage capacity.

2.1.4 Mineral trapping:

Refers to the incorporation of CO_2 in a stable mineral phase via reactions with mineral and organic matter in the formation. Over time the injected CO_2 will dissolve into the local formation water and initiate a variety of geochemical reactions. Some of these reactions could be beneficial, helping to chemically contain or "trap" the CO_2 as dissolved species and by the formation of new carbonate minerals; others may be deleterious, and can actually aid in the migration of CO_2. It is important to understand the overall impact of these competing processes. However, these processes will also be dependent upon the structure, mineralogy and hydrogeology of the specific lithology concerned [11].

2.2 Potential leakage mechanisms in CO_2 CCS:

A successful CO_2-CCS project depends mainly on its storage capacity (how much we are injecting?), its efficiency (the quantity that's going to be trapped there?) and its security (for how long?) therefore, any Possible leakage pathways or mechanisms represent a major concern and represent a risk to the project's goal as a whole. Leakage pathways identified are:

2.2.1 Through the pore system in low-permeability caprocks:

Physical trapping of CO_2 in the reservoir will occur along the top surface of a given storage formation, underneath the top seal and structural traps. There, the bypassing, mobile CO_2 plume will fill small traps, with efficient CO_2 capture. In most cases, the numerous intervening stratigraphic traps limit the rate to orders of magnitude less than the rate of seepage/leakage from the processes such as micro fracturing and/or pore dilation [41].

Flow of CO_2 through intact caprock greatly depends on the permeability of the rocks, which in turn is very sensitive to stress and pressure changes. Numerical simulations of the hydromechanical response of the reservoir associated with injection of CO_2 indicate that injection can reduce the mean effective stress in the reservoir. This will also lead to an increase in pore pressure in the parts of the caprock adjacent to reservoir, causing pore dilation and changes in the permeability of the caprock. Furthermore, pore dilation will also increase the pore radii and thus reduce the capillary entry pressures, facilitating leakage. Shales, poorly lithified sandstones and sand have compressibilities that are very sensitive to stress changes, this sensitivity is even stronger at low effective confining pressures that are expected to develop during prolonged injection. In such stress-sensitive formations, CO_2 flux might increase by orders of magnitude with increasing fluid pressure.

In order to evaluate the potential CO_2 flux through the primary caprock for different stress and pressure conditions, assuming no faulting or fracturing of the caprock and reservoir. First, the effective Darcy permeability for CO_2 has been studied in the same experiments as for CO_2 entry pressure. High confining pressure was applied in order to avoid hydro fracturing of the sample and Darcy flow was imposed upon shale samples in the experiments by [4]where a slight decline in effective CO_2 permeability (range of 10-18–10-24 m^2) was measured compared to the water permeability (range of 10^{-19}–10^{-21} m^2). Brine permeability in the range of 3–10×10^{-19} m^2 was measured for the Nordland shales [24] measured effective CO_2

permeability in the order of 10^{-21} m^2, within the same order of magnitude as for brine permeability, and the effective CO_2 permeability was found to depend on volumetric dilation in the sample.

2.2.2 Erosion of well completing cement and corrosion of pipelines as possible leakage mechanisms:

Injection wells for carbon dioxide are made of iron casings supported by cement. Cement primarily contains calcium oxide, which transforms into calcium carbonate in reactions involving carbon dioxide. Cement also contains other clay materials similar to calcium carbonate in terms of water structuring effects and adsorption thermodynamics. Moreover, iron transforms into iron oxide, due to sodium chloride and the acidic environment.

Pipelines are rusty even before they are installed. While rust generally consists of a mixture of iron oxide, FeO, hematite, Fe_2O_2 and magnetite Fe_3O_4 the most important of these is hematite, and it may therefore be used in studies as a model for rust. Abandoned oil and gas wells in the vicinity of an underground aquifer, plugged with cement, as well as the injection well itself, are subject to further corrosion of the rusty metal surfaces. Erosion of the cement happens due to an acidic water environment containing dissolved (and dissociated) CO_2 as well as gas bubbles that are incorporated due to the local hydrodynamics.

There are two reasons for the existence of space in between the rusty pipeline and the cement. First, it is geometrically impossible to achieve total beneficial direct contact between the surfaces of rust and cement due to the distribution of charges on the two surfaces. Second, and even more importantly, are the exothermic reactions during drying of the cement which evaporate water and lead to channel creation. Studies are done on erosion and corrosion in an acidic water environment and CO_2. Applying the principles of quantum mechanics in order to characterize charge distributions in cement and rust, and molecular dynamics simulations to evaluate adsorption structures, composition and thermodynamic properties". These characteristics are long-term effects, and adsorption is highly non-uniform. Large simulation systems are therefore needed in order to develop a basis for further reaction studies [54].

2.2.3 Flow through existing faults and fracture networks:

Faults and associated fracture networks can significantly influence the flow of groundwater, hydrocarbons or CO_2. They can act either as barriers to fluid flow or as conduits for fluid circulation. The presence of an intensive fracture network around faults, e.g. in low-porosity formations, can enhance fault permeability, while deformation bands in the fault damage zone might behave as seals for fluid flow. Most studies emphasize the strong influence of fault zone architecture on fault-zone hydraulic properties. Field studies of natural CO_2

reservoirs, which are widespread in sedimentary basins worldwide, show that the fracture networks developed in the damage. Based on the data presented, using the bleaching as a proxy for past fluid migration, we hypothesize that such fracture corridors, which connect localized reservoirs at different stratigraphic levels up towards the surface, represent preferred fluid migration pathways rather than the main faults. The corridors are found [33].

- ✓ In the damage zone of faults;
- ✓ At fault tips where displacement disappears;
- ✓ Along the crest of gentle folds oriented perpendicular to faults.

The data that are most suitable for studies of CO_2 leakage in the subsurface come from the oil and gas industry, as the processes that result in leakage of CO_2 and hydrocarbons are the same, although they operate at different timescales. Some investigations have been run on the controls of hydrocarbon–water contacts in many Norwegian oil and gas fields, and considered the reasons for leakage from a set of dry structures presented in several MSc theses.

We came to the conclusion that leakages have taken place along faults or at fault intersections from many structures, as documented by for the Barents Sea. The leakages were probably comparatively rapid and short-lived, and the overpressures were not been drained from leaky and over pressured compartments. Overburden bright spots are often seen along and/or above "The presence of an intensive fracture network around faults, e.g. in low-porosity formations, can enhance fault permeability, while deformation bands in the fault damage zone might behave as seals for fluid flow." leaky faults This means that faults and fault intersections especially could be leakage pathways for injected CO_2. Geophysical monitoring is especially important when the CO_2 injected meets such features, and a back-up plan needs to be in place to handle leakage though faults. The leakage that we have identified appears to be controlled by shear failure. (Figure II.3) will preview the potential leakage mechanisms.

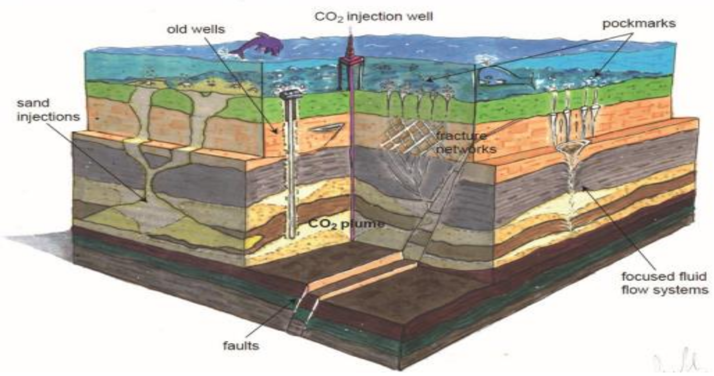

Figure II.3: Outline of possible leakage pathways for CO_2.

3. Reservoir proprieties, characterization and selection:

3.1 Optimal storage locations:

3.1.1 Abandoned oil and gas fields:

Depleted oil and gas reservoirs are prime candidates for CO_2 storage for several reasons. First, the oil and gas that originally accumulated in traps (structural and stratigraphic) did not escape (in some cases for many millions of years), demonstrating their integrity and safety. Second, the geological structure and physical properties of most oil and gas fields have been extensively studied and characterized. Third, computer models have been developed in the oil and gas industry to predict the movement, displacement behavior and trapping of hydrocarbons.

Finally, some of the infrastructure and wells already in place may be used for handling CO_2 storage operations. Depleted fields will not be adversely affected by CO_2 (having already contained hydrocarbons) and if hydrocarbon fields are still in production, a CO_2 storage scheme can be optimized to enhance oil (or gas) production. However, plugging of abandoned wells in many mature fields began many decades ago when wells were simply filled with a mud-laden fluid. Subsequently, cement plugs were required to be strategically placed within the wellbore, but not with any consideration that they may one day be relied upon to contain a reactive and potentially buoyant fluid such as CO_2. Therefore, the condition of wells penetrating the caprock must be assessed. In many cases, even locating the wells may be difficult and caprock integrity may need to be confirmed by pressure and tracer monitoring. The capacity of a reservoir will be limited by the need to avoid exceeding pressures that damage the caprock. Reservoirs should have limited sensitivity to reductions in permeability caused by plugging of the near-injector region and by reservoir stress fluctuations. Storage in reservoirs at depths less than approximately 800 m may be technically and economically feasible, but the low storage capacity of shallow reservoirs, where CO_2 may be in the gas phase, could be problematic. [6]

3.1.2 Saline aquifers:

Represent the best salted sink for storage of CO_2 among all geological options due to their enormous storage capacity [36]. It is required that the aquifer be saline because this already makes it unsuitable for industrial, agricultural and human purposes. Other storage modes which have been employed for the storage of CO_2 include basalts and mineral carbonation. Among all geologic sequestration mechanisms, deep saline aquifers represent the ones exhibiting highest sequestering capability, as against those provided by depleted oil and gas reservoirs and unmineable coal beds [22].

3.1.3 Deep unmineable coal beds:

CO_2 has been employed for the recovery of methane from coal seams during the enhanced coal bed methane (ECBM) recovery process [3]. Produced methane from this source can be utilized as an energy source. Coal beds have very large fracture networks through which gas molecules can diffuse into the matrix and desorb tightly adsorbed methane. CO_2 has been proven to raise methane recovery to about 90% from 50% when conventional methods are applied. Injected CO_2 is stored in the formations after methane has been recovered. Storage in coal beds can take place at shallower depths than other formation types and as such relies on CO_2 adsorption on the coal surface. However, the technical feasibility of this storage process strongly depends on the coal's permeability as a result of its depth variation with the influence of effective stress on coal fractures [22].

3.2 General site selection criteria:

The selection of safe and secure sites in the first place is the most important aspect for not only to increase the public acceptance of geologic CO_2 storage, but also, it is the most important condition for a technically and economically successful commercial simultaneous CO_2-EOR and storage projects. In this section, different aspects of CO_2 storages are discussed and major parameters required for a suitable storage site selection are emphasized. [40]

3.2.1 Storage capacity:

Storage capacity is defined as the total volume of a geological medium that can possibly be used for storage purposes, it depends mainly on subsurface pressure and temperature conditions at which CO_2 appears at supercritical state. This is linked to the fact that reaching the supercritical condition is essential for CO_2 to approach a high density and gas-like viscosity, resulting in a complete pore volume utilization and mobility within a reservoir

There have been many studies where an efficient storage is reported to be the one taken place in the reservoirs located at the depth of more than 800m. Pressure, temperature and density variations are playing important roles in these cases. For instance, the density of CO_2 increases with depth and this enhances the storage capacity considering the fact that a dense CO_2 occupies smaller pore volumes. Porosity is another parameter which should be high enough for having a good storage capacity, even though it decreases with depth due to compaction and cementation phenomena. Other parameters such as the mobility and buoyancy of CO_2, and irreducible water saturations can also reduce the capacity of a storage medium. [40]

3.2.2 Injectivity:

Injectivity is the ease with which fluids can flow through stratigraphic intervals. It related directly on Permeability and thickness of storage sites.

In general, permeability near the well bore must be greater than >100 mD for a favorable injectivity. However, the permeability of a medium should be low to ensure that a permanent storage can take place. Stated that a high permeable site is less expensive for CO_2 storage due to lesser number of wells required for the favorable injection.

The reservoir pressure increases during the CO_2 injection and eventually reduces the injectivity to compensate the excessive pressure build-up. This might be a problem for sequestration exercises in an aquifer as the significant pressure build up may not be released due to the resistance of brine in pore spaces. It is also reported that the reservoir pressure should not exceed the seal (caprock) fracture pressure in order to mitigate the escape of CO_2 to the atmosphere.

Capillary trapping is probably one of the trapping mechanisms with known impacts on the injectivity. The entrapment of injected CO_2 in the pore space of rocks surrounded by water develops what is known as the residual CO_2 saturation during the capillary trapping. This residual saturation is impacted by rock properties and can be measured experimentally in a lab. The residual gas in depleted reservoirs may significantly increase or decrease the storage capacity. It also reduces the brine mobility and decreases the density and viscosity of gas mixtures when it dissolves into the supercritical CO_2.[40]

3.2.3 Trapping mechanisms:

The efficiency of the trapping mechanism depends mainly on reservoir characteristics and in-situ parameters [47] Generally speaking, site selections based on dominant trapping mechanisms are essential to prevent any leakage to surface or subsurface resources.

The geometry of pore spaces, rock–fluid interactions and fluid–fluid interactions play vital roles when it comes to the CO_2 storage in a geological medium. The Laplace model represents these interactions (Eq. (1)), which affect the flow process and in the long-term, control the capillary-sealing efficiency:

$$P_{CO2} - P_{Brine} = \frac{2\gamma_{b.CO2}\cos\theta}{R} \tag{1}$$

In the above equation, Pc is the capillary pressure, $y_{b.CO2}$ is the interfacial tension between brine and CO_2, R is the largest connected pore throat and θ is the contact angle representing the medium wettability.

There are numerous parameters which can control the capillary trapping, including vertical permeability, thermodynamic properties of a CO_2-H_2O phase, heterogeneity, etc. For instance, brine viscosity reduces the chance of having a good capillary trapping mechanism. Interfacial tension is another parameter which is linked to the residual CO_2 saturation The CO_2–brine interfacial tension is less than that of a hydrocarbon–brine and thus, a lower residual gas saturation is usually observed in a CO_2-brine system. The Interfacial tension decreases with increasing the pressure and is impacted by the temperature to a great extent.

Contact angle is the parameter quantifying the wettability in a CO_2-brine system. According to [23], the contact angle has a great impact on the capillary trapping in a water-wet system because CO_2 appears occasionally in a non-wetting phase [40]. In a non-water-wet system, therefore, the pressure on the seal is increased by the CO_2 plume resulting in fracture initiations and leakages through the site.

When it comes to the solubility trapping, a high temperature and low-pressure conditions result in having a low-density CO_2, which in turn causes the CO_2 plume to flow at a higher rate and makes the monitoring far more complicated, the CO_2 solubility is favorable in the low temperature and low saline areas.

Table II.1: The effect of pressure, temperature and salinity on the mineral trapping [40].

Rock Type/Basin	Major Minerals	Water type/ionic strength	T (°C)	P (MPa)	Outcome
Glauconitic sandstone, Alberta Basin	Quartz (87%), K-feldspar (2%0, plagioclase (1%), glauconite (5%), kaolinite (2%), calcite (1%), dolomite (1%), siderite (1%)	Saline water with high salinity	105	9	Very little reaction observed in fast-reacting carbonate mineral due to high salinity
Sandstone from Rio-Bonito Formation, Brazil	Quartz, albite, arnorthite, calcite, dolomite, illite, kaolinite/chlroite and illite-smectatite mixed layer	0.1 M Nacl solution	80	0-12	No reaction after 3 months Part of illite-smectatite mixed layer turned into illite
Navajo sandstone, Colorado, USA	Quartz (90%), feldspar (2%), smectatite, kaolinite	0.2 mol/kg KCL	200	30	Dissolution of feldspar and conversion of smectatite to illite are the main reactions observed. Chemical reaction induced by CO_2 injection cause pore throat clogging by moving the smectatite
A number of sandstone types from North Germen Basin	Quartz, feldspar, calcite, illite, barite, chlorite kaolinite	Formation brine	100	10	Development of micro-fractures in detrital minerals Initial dissolution of calcite

3.2.4 Containment (sealing capacity):

Containments of a storage site depend mainly on the characteristics of caprocks, faults and fracture surrounding a reservoir. A fault must have a permeability of less than 0.1mD and should be surrounded by clays and evaporites or other impervious rocks in order to be counted as a reliable seal. [40]

Seals capacity, their geometry and integrity are the most important aspects of containment when it comes to the storage site reliability analysis. The sealing capacity of a fault, however, is affected by the pore-throat size, contact angle (wettability) and interfacial tension of rock forming minerals [42]. These minerals, are strongly water-wet and favor the sealing ability of caprocks or faults against the leakage of the CO_2 plume [49].

Thickness of a seal is another aspect of integrity analysis which should not be neglected [32]. According to [49], a seal must have a thickness of at least 10m to provide resistance against the CO_2 plume pressure.

A seal integrity changes by the increase of the pore pressure and stress variations induced due to the injection. A significant increase of the pressure during the injection decreases the normal stress on a fault surface and causes the mechanical break-down (reactivation) [40]

3.2.5 Cost:

The cost of transportation of CO_2 from a source to storage sites depends mainly on locations (e.g. Onshore or offshore), the size and composition of pipelines and operating conditions. According to [22], transportation cost is estimated to be around 1-8 USD/tCO_2 per 250 km pipeline and released in the recent years indicated that as long as the distance between major sources and prospective sedimentary basins is less than 300 Km, transportation may not induce excessive costs on storage projects [22]. Non-condensable impurities such as N_2, O_2 and Ar which are often mixed with CO_2 during the capturing practice may also pose extra costs on storage projects [10].

Table II.2: The screening criterion proposed for the CO_2 storage by [10]

Parameters	Positive Indicators	Cautionary Indicators
Total Storage Capacity	Total Capacity of reservoir estimated to be much larger than the total amount produced from the CO_2 source	Total capacity of reservoir estimated to be similar or less than the total amount produced from the CO_2 source
Depth	1000-2500 meter	<800m or >2500m
Thickness (net)	>>50m	<20m
Porosity	>20%	<10%
Permeability	>300mD	10-100mD
Salinity	>100 g/L	<30 g/L
Seal Properties		
Lateral Continuity	Un-faulted	Laterally Variable Faults
Thickness	>100 m	<20 m
Capillary Entry Pressure	Mush greater than buoyancy force of maximum produced CO_2 column high	Similar to buoyancy force of maximum produced CO_2 column height

4. Effect of Reservoir properties on the storage capacity and security:

4.1 Effects of Heterogeneity:

Heterogeneity can be shown to increase storage efficiency, as described by [53] if the formation being injected into is sufficiently thick (50-100m) then injection should occur in the deeper part of the formation. The buoyant nature of the injected CO_2 will cause the CO_2 to migrate upwards through the formation, facilitating residual trapping mechanisms to immobilize a portion of the CO_2. The instability of the CO_2 plume was thought to lead to fingering, but simulations have demonstrated that the CO_2 will actually follow preferential flow paths defined by the heterogeneity. This means that the heterogeneity that complicates simulations actually has the potential to increase trapping in thicker formations. In oil production, this heterogeneity is seen as a problem, whereas with the objective of CO_2 storage, it can be an advantage.

Greater heterogeneity in the form of shale barriers reduces vertical permeability by increasing the tortuosity of migration pathways, and thus lateral movement is favored over vertical migration [35] proper upscaling of the permeability distribution then becomes important for field-scale simulation.

A simple analytical expression has been derived for the mean and variance of the vertical permeability in a reservoir with randomly distributed impermeable barriers show that the variance is inversely proportional to the reservoir thickness whereas the mean vertical permeability is scale invariant. Two-dimensional numerical modelling and extension to 3D predict that breakthrough of CO_2 injected at moderate rates at the bottom of the reservoir would scale as the square of reservoir thickness h in 2D and as h^3 in 3D[39]. Thus, deep injection in thick heterogeneous formations can result in slow vertical migration and high trapping efficiency in the formation (Figure II.4). It was also found that, on a small scale, downward convection of dissolved CO_2 (due to the slight density increase of the fluid upon dissolution) began much sooner in heterogeneous cases than in homogeneous cases (Figure II.5)

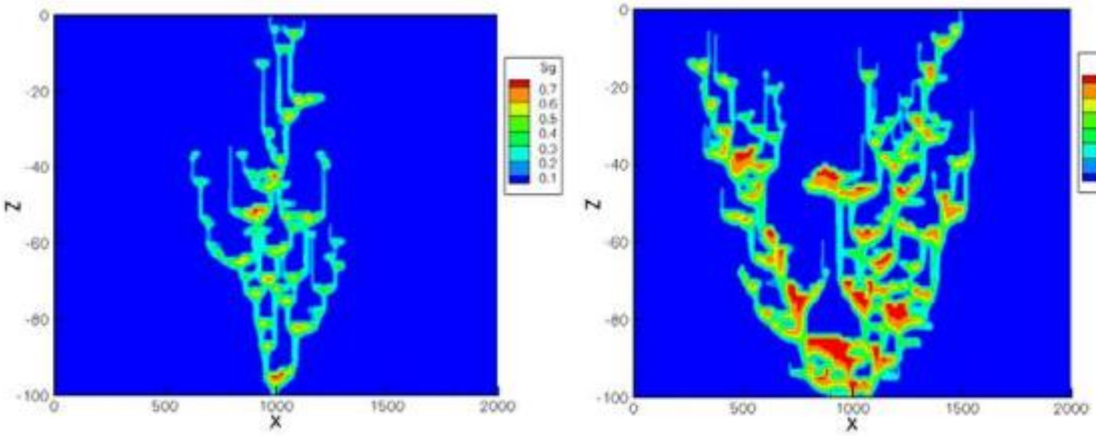

Figure II.4: Impact of heterogeneity and injection rates on the vertical spread of CO_2 injected at the bottom of a reservoir.

The CO_2 saturation Sg is shown at the time of breakthrough at the top of the reservoir; left: 0.001 kg/s (per meter of thickness), right: 0.01 kg/s

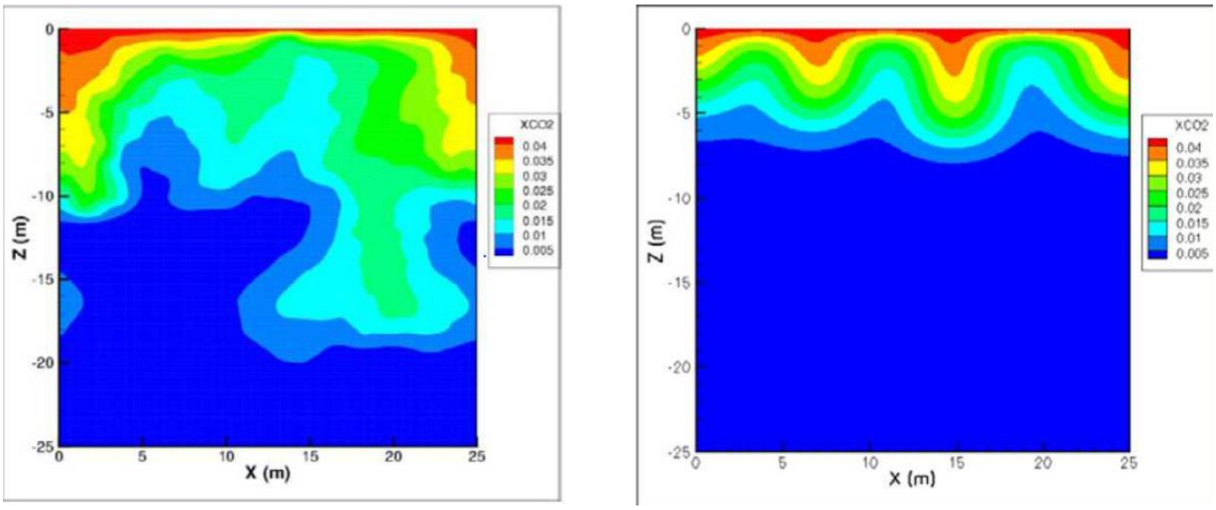

Figure II.5: Impact of heterogeneity on the convection of dissolved CO_2

Showing initiation of fingering for a 25 m x 25 m domain with a top boundary condition of constant dissolved CO_2. Left: statistical distribution of shales with fraction of impermeable barriers = 0.153 and width = 1.5 m, Right: homogeneous permeability with same effective vertical and horizontal permeability [39]

4.2 Effect of Formation pressure:

According to the universal gas laws, if the pressure of the carbon dioxide decreases, its volume will increase. Therefore, if the trap was filled full of carbon dioxide and if over time the pressure trap decreases, there will be a leakage of carbon dioxide into the underlying aquifer. However, the water and capillary pressure are focused on as well to find the pressure that the carbon dioxide in the trapping mechanisms within the formation is subjected to with the argument that the pressures of the carbon dioxide and water phases (P_{CO2} and P_W) are related by the capillary pressure (P_C) and water saturation (S_W) according to eq. (2): **[16]**

$$\mathbf{P_{CO2} = P_W + P_C\ (S_W)} \qquad \mathbf{(2)}$$

To correctly estimate the storage capacity, the injected CO_2 pressure should be equal to the maximum capillary pressure of the trapping rock. And should be limited at 9-18% of the original formation (aquifer) pressure (According to Dutch engineers). the maximum injecting pressure specified by French engineers to be 1.3-1.5 times P_w for depth (d) of 300-1300 m, as shown in eq. (3)

$$\mathbf{P_{MAX} = 1.35\ P_W\ \text{for: } d < 1000\ m} \qquad \mathbf{(3)}$$

However, in oil and gas reservoirs the maximum pressure is defined by the pressure that causes hydraulic fracture in the formation.

4.3 Effect of formation injectivity and permeability:

Injectivity measures the possibility of inserting a fluid into a geological formation and is characterized by the rate at which carbon dioxide can be injected and the ability of carbon dioxide to migrate from the injection well, and is usually dependent on the permeability and porosity of the formation as well. Injectivity is a major determinant of the suitability of the site for carbon dioxide storage and it is defined as: the ratio of well volumetric flow (q) to the correspondent pressure drop (ΔP) as shown in the eq (4):[16]

$$\boldsymbol{I = \frac{q}{\Delta P}} \qquad \mathbf{(4)}$$

4.4 Effect of the formation temperature:

In the whole process of CO_2 storage, we seek the highest rates of CO_2 solubility in water, the relationship between the solubility of CO_2 in water and the reservoir's temperature under a certain pressure is shown in (figure II.6). if the temperature increases the salinity increases, in other words, the deeper the reservoir, the greater solubility of CO_2 in it. Thus, more secure storage.

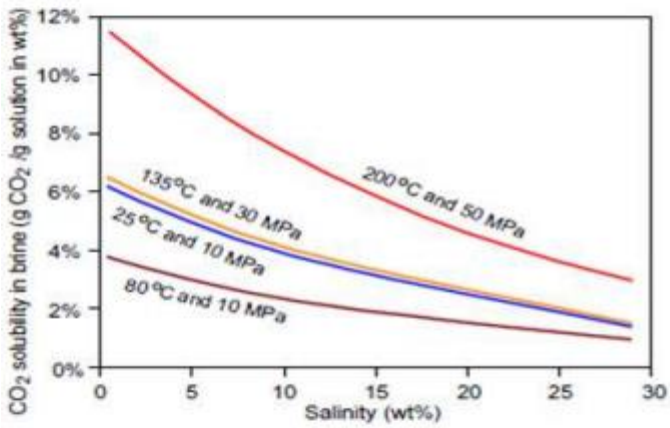

Figure II.6: CO_2 Solubility in brine vs. salinity at different temperature and pressure.[16]

4.5 Effect of reservoir compressibility:

The pore volume needed to store injected carbon dioxide after a given injection time is provided by contributions from three factors, namely the expanded storage volume in the storage formation caused by pressure build-up. The expanded storage volume within the seals is due to the pressure build-up and the volumetric leakage of brine into the formations above the upper seal and below the lower seal. This expanded storage volume is caused by both brine and pore compressibility, the brine and pore compressibility, CW and CP are shown in the eq (5) and (6), respectively: .[16]

$$Cw = \frac{1}{\rho_W(\frac{\delta\rho_W}{\delta P})} \quad (5)$$

$$Cp = \frac{1}{\phi_f(\frac{\delta\phi'_p}{\delta P})} \quad (6)$$

4.6 Effect of fractured formation:

To estimate the impact of fractures on the storage capacity a series of pressure tests have been applied by [16]on two reservoirs (fractured and homogeneous), both reservoirs have same properties the only difference is the fracture properties in the fractured one. The obtained results show the important effect of the fractures on the stored amount of CO_2, in other words, the effect on the storage capacity. The results are briefly stated below:

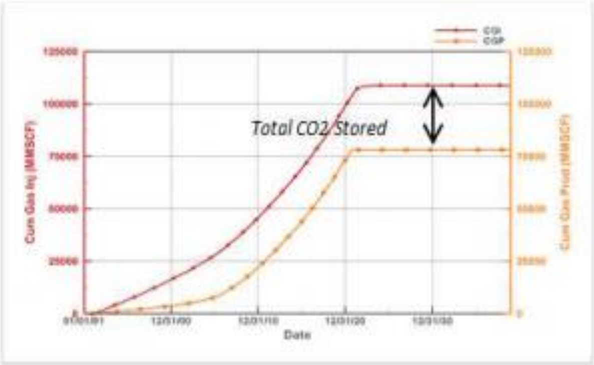

Figure II.7: Total CO_2 stored in homogenous reservoir [16]

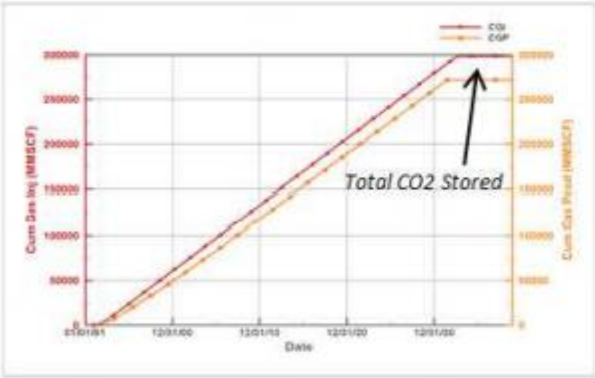

Figure II.8: Total CO_2 stored in fractured reservoir [16]

The total CO_2 stored in the homogenous reservoir expressed as: [16]

$$\textbf{Total } CO_{2\,\text{stored}} = \textbf{total } CO_{2\,\text{injected}} - \textbf{Total } CO_{2\,\text{produced}} \quad \textbf{(7)}$$

Both figures (II.7) and (II.8) show that the amount of stored CO_2 in the fractured reservoir is way less than the amount of CO_2 stored in the homogeneous reservoir, which means the fractures in the reservoir are an easy way out for the injected CO_2 and that goes against the whole purpose of sequestrating CO_2 underground

According to the previous results and analysis we note that the storage capacity of the homogeneous reservoirs is higher than the fractured reservoirs due to the dual feature of the fractured reservoir, where the presence of the fractures in the formation helps the CO_2 to flow through the less resistant path [16].

The fractures have always been regarded as potential escape routes for CO_2, which could damage the prospective storage ability of a specific storage site. Fractures have low storage and high permeability values compared to the matrix. These high permeabilities of the fractures could potentially allow CO_2 to migrate quickly through the cap rock to the surface or to neighboring aquifers. Local pressure increase caused by CO_2 injection can also lead to hydro fracturing in the vicinity of wells.

4.7 Effect of Rock type and stratigraphic column:

To study the relationship between rock type and the security of CO_2 storage [25] studied 76 naturally occurring co_2 reservoirs to find that there's no relationship between successful CO_2 retention and the lithology of the reservoir or caprock in reservoirs for which this geological information is available (64 of 76 reservoirs). Naturally occurring CO_2 reservoir rocks are commonly siliciclastic (37 reservoirs) or carbonate (24 reservoirs), or interlayered (11 reservoirs). Silicate mudstones and shales (43 reservoirs) are the dominant caprock lithology, with fewer cases of evaporite-bearing caprocks (1_2 reservoirs), or interlayered carbonate and siliciclastic seals (3 reservoirs). [25]

4.8 Effect of CO_2 fluid properties (density):

Reservoir temperatures range from 20 to 200 ◦C, with insecure reservoirs having either "normal" (30 ◦C per km) or very high geothermal gradients. At pressures and temperatures below the critical point (7.38 MPa, 31.1 ◦C) CO_2 will be gaseous and exhibit densities of <470 kg/m3 while at conditions above the critical point it will be supercritical and shows a wide range of densities (<200–1000 kg/m3). Calculated CO_2 densities based on reservoir pressures and temperatures range from 15 to 919 kg/m3 (Figure II.9). CO_2 is therefore securely contained in subsurface reservoirs in gas (8 out of 76 reservoirs) and supercritical CO_2 phases; not as a liquid. It also exists as a dissolved phase, which has been shown to be a significant CO_2 trapping mechanism in natural CO_2 reservoirs by several studies. Insecure reservoirs typically contain CO_2 in a gaseous state (with an average density of 110 kg/m3) (Figure II.9-A). Reservoirs containing CO_2 in a gaseous state are more prone to migration than reservoirs containing supercritical CO_2 (Figure II.9-A): 27% (3 out of 11) of reservoirs with gaseous CO_2 showing evidence for CO_2 migration, while only ∼5% (3 out of 65) of deeper reservoirs containing CO_2 as a supercritical phase exhibit CO_2 evidence for migration to the surface. [25]

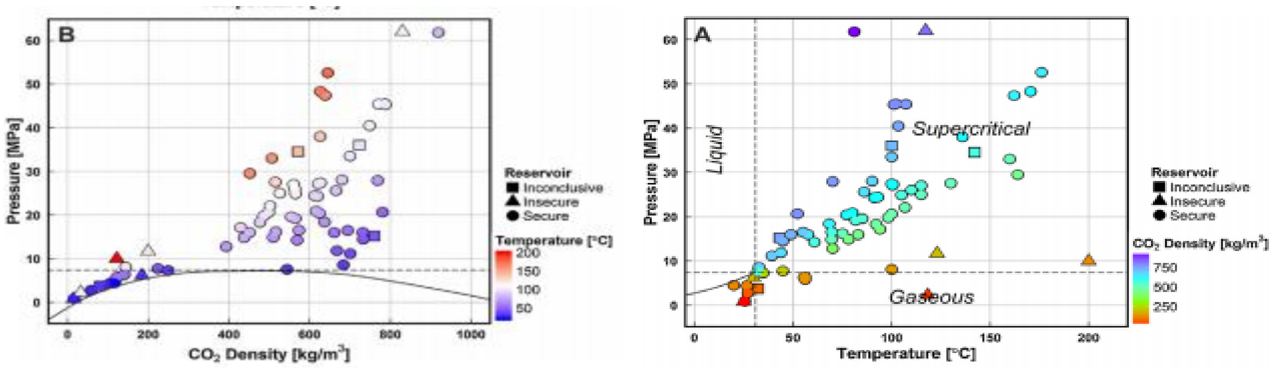

Figure II.9: CO_2 state diagrams of the studied naturally occurring CO_2 reservoirs. [25]

4.9 Effect of Geological structure (faults):

Where data are available for the $_2$1 multi-layered CO_2 reservoirs, we observe CO_2 is migrating between these stacked formations via faults or fractures. For 5 of the 6 insecure CO_2 reservoirs, the migrating CO_2 emerges at the surface as CO_2 rich springs and travertine deposits within 5 km to the surface traces of faults, showing the influence of faults on crustal fluid flow, in the near surface at least. However, over half of the secure reservoirs are fault bound structural traps, and several more are located in structurally complex and faulted provinces, indicating that faults more often inhibit CO_2 migration rather than permit it. Importantly, the majority of the insecure reservoirs are found in tectonically active regions.

The fractures have always been regarded as potential escape routes for CO_2, which could damage the prospective storage ability of a specific storage site. Fractures have low storage and high permeability values compared to the matrix. These high permeabilities of the fractures could potentially allow CO_2 to migrate quickly through the cap rock to the surface or to neighboring aquifers. Local pressure increase caused by CO_2 injection can also lead to hydro fracturing in the vicinity of wells. [25]

5. Conclusion:

A successful carbon dioxide storage project would involve accurate site selection, characterization (storage capacity estimation...) and monitoring to avoid the risks of leakages through seals, faults and abandoned wells. The site characterization would be successful through the use of modeling and simulation tools whose accuracy would be greatly enhanced through measurement, monitoring and verification during the post-injection phase. Carbon dioxide storage is a technology that has come to stay with the advantage of allowing the continued use of fossil fuels while still saving our environment from the risks of global warming

Chapter III:

Enhanced oil recovery and sequestration (EOR+) by injecting miscible CO_2 gas.

1. Introduction:

For more than four decades, the petroleum industry has been using the anthropogenic CO_2 for EOR purposes. In CO_2-EOR operations, a significant portion of injected CO_2 is lost in the reservoir in anyway leading to its partial (incidental) storage even though they are not designed with long-term storage purposes. With an inclusion of additional storage-focused activities (i.e. a dedicated MVA/MMA program) an EOR project can become a storage project (i.e. simultaneous CO_2-EOR and storage project). An MVA/MMA program essentially includes a minimum of following four activities [27]:

- Additional site characterization and risk assessment to evaluate the storage capability of a site;
- Additional monitoring of vented and fugitive emissions;
- Additional subsurface monitoring, and
- Change to field abandonment practices.

The petroleum industry's long and successful record of secure underground injection of CO_2 for EOR, has helped the world to embrace the geologic CO_2 storage as first-order technology for abating the anthropogenic Green House Gases emissions.

2. CO_2-EOR Overview and background:

One of the attractive and emerging technologies for climate change mitigation due to CO_2 emission is CO_2-enhanced oil recovery (EOR) apart from its geological sequestration, also sometimes known as Carbon Capture and Storage (CCS). With the help of technical and economical assessments, experts suggest that CCS could contribute up to $_2$0% of CO_2 emission reductions, which is equivalent to the cutbacks anticipated from efficiency improvements and large-scale deployment of renewable energy resources [48]. This technology involves capturing of CO_2 from emission sources such as petroleum extractive plants.

In general, oil and gas production is classified into three recovery processes: primary, secondary, and tertiary. The tertiary recovery, also called enhanced oil recovery (EOR) is the process, which is implemented in oil and gas fields to increase the recovery of crude oil that can be extracted from the field. EOR, sometimes also known as improved oil recovery can be accomplished by various techniques such as thermal, chemical (surfactant, polymer, etc.) and gas (miscible/immiscible) injection.[50]

Amongst the various EORs, CO_2-EOR is found to be widely used process since it provides a unique opportunity to gain a considerable financial return for storing anthropogenic CO_2 once oil production diminishes prior to its abandonment. During this process, injected CO_2 interacts physically and chemically with the reservoir rock and the contained oil, creating favorable conditions to mobilize the stranded oil and forming a concentrated oil bank that is swept towards a production well (Figure III.1).

A successful CO_2-EOR project could add 5–15% of additional oil recovery after primary and secondary recovery efforts, which is typically in the range of 30– 35% of oil originally in place (OOIP) [37].

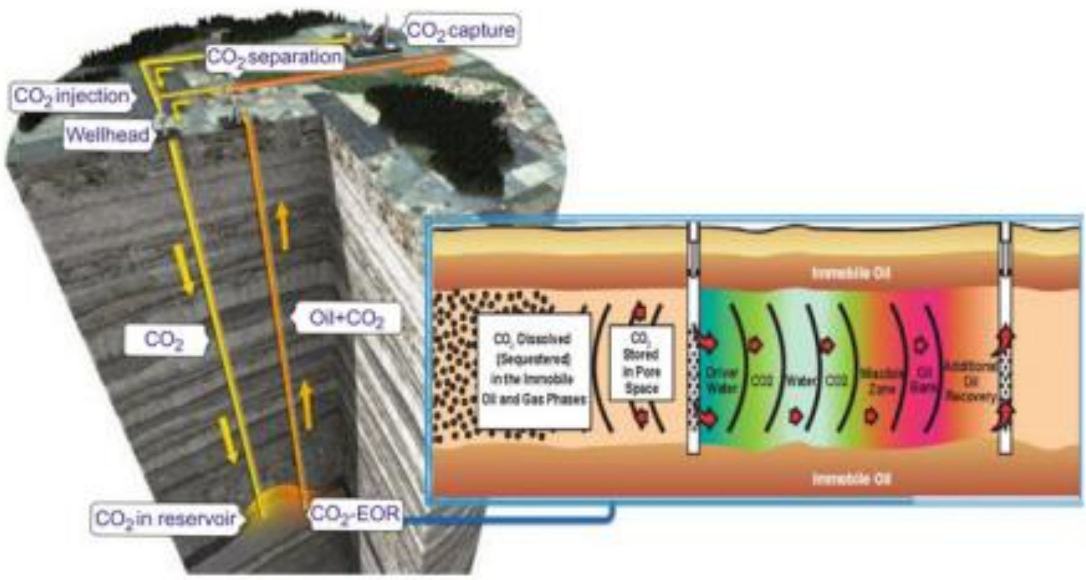

Figure III.1: Schematic representation of CO_2-EOR and sequestration subsequently in a field. Cross-section of formation of oil bank during water-alternating-gas injection is also depicted [2].

3. CO_2 storage for enhanced oil recovery processes:

3.1 Injection Strategies:

The conventional WAG injection and continuous CO_2 injection, both in miscible mode, are the two injection strategies that operators have mainly utilized in currently operational LSIPs and other simultaneous CO_2-EOR and storage projects. In conventional WAG, a predetermined volume of CO_2 is injected in cycles alternating with equal volumes of water [38].

The petroleum industry has preferred the WAG process because it helps in reducing the mobility of CO_2 in the reservoir. The injection of water along with the CO_2 helps in overcoming the gas override and reduces the CO_2 channeling thereby improving overall CO_2 sweep efficiency [38].

Although the use of WAG injection strategy yields better results that continuously injecting CO_2, WAG may still leave lot of oil (approximately one third to two-thirds of the oil left behind by water flooding) behind [39]. On the other end, a WAG injection strategy will essentially result in less CO_2 stored in the reservoir compared to a continuous CO_2 injection in miscible mode. From storage point of view, use of WAG results in the reduction of pore space that may be otherwise available for injection CO_2. Also, the projects not optimized for storage, may only store up to 50–60% of the total emissions resulting from the combustion of oil/gas produced in the project and the energy consumption and other operation emissions occurring during in the entire process of producing them (reservoir to the end use point). However, optimization of injection strategies can assist us in making the EOR and storage projects "net zero emissions" projects (i.e., storing more CO_2 than the CO_2 generated by the energy consumption, operational emissions, and the end use (combustion) of the produced oil/gas).

3.1.1 Overall Oil Recovery Factor:

Basically, for a simultaneous CO_2-EOR and storage project, overall recovery factor (RF), defined as the volume of oil recovered over the volume of original oil in place (OOIP), can be described as a product of following four efficiency terms [5]:

- ✓ The macroscopic sweep efficiency, ES, which is the fraction of the connected reservoir volume that is swept by the injected fluids.
- ✓ The microscopic displacement efficiency, EPS, described as the fraction of oil displaced from the pores by the injected fluids (water and/or CO_2), in those pores which are contacted by the injected fluids.

- ✓ The connected volume factor, ED, represents the proportion of the total reservoir volume connected to the wells.
- ✓ The economic efficiency factor, EC, which imposes additional physical and commercial constraints on the project life. Hence, an equation for overall RF can be written as:

$$\mathbf{RF = E_S\, E_{PS}\, E_D\, E_C} \qquad \mathbf{(8)}$$

For detailed explanations of efficiency factors view: [14]

3.1.2 Storage Capacity:

Recovering maximum oil while keeping all the injected CO_2 in the reservoir is a challenge to any simultaneous CO_2-EOR and storage project. An operator always aims for the use of minimum mass (or volume) of CO_2 to recover a barrel of oil. However, for a simultaneous CO_2-EOR and storage project, it is equally important that the project can inject a desired amount of CO_2 and produces a minimal portion of the injected CO_2 back to the surface. Typically, any of the produced CO_2 is processed (i.e., separated from production fluids (oil and water), dried, re-compressed, and re-injected back either in the same reservoir (another injection area/phase) or in another project nearby.

There are certain approaches have been suggested in the published [31]; [7]; [19] for increasing CO_2 storage in oil recovery.

One of the options is to optimize the water injection (timing, injection rates, and WAG ratio) to minimize gas cycling and maximum gas storage. Another option is not only considering reservoir re-pressurization after the end of the producing life of the field, but also, the candidate depleted reservoir can also be re-pressurized via CO_2 injection instead of raising reservoir pressure above MMP via water flooding. Reservoir re-pressurization during the disposal of acid gas (67% CO_2 + 33% H_2S) resulting from natural gas processing, had resulted in recovering additional oil from Zama F Pool [13], and led to launch a formal project to for demonstrating the viability of simultaneous CO_2-EOR and storage project in closed pinnacle reef structure.

Another strategy will be not re-injecting produced water and recycled CO_2 into the reservoir back but injecting any of the recycled CO_2 into a saline aquifer while disposing the produced water into an exempted (non-USDW) aquifer. Injection of CO_2 for recovering oil from the “residual oil zones” (ROZs) that may be encountered in naturally water-flooded intervals below the established oil-water contacts also appears to be a potential way for enhancing CO_2 storage in EOR projects.

3.2 Alternative Injection Strategies:

3.2.1 Gas Assisted Gravity Drainage (GAGD):

Apart from conventional WAG and continuous CO_2 injection in miscible mode that mainly rely on pattern flooding, an alternative injection strategy, namely, Gas Assisted Gravity Drainage (GAGD) process [12] appears to be a promising injection strategy from both oil recovery and storage capacity point of view. A review of the use of gravity drainage concept in the field shows that it is applicable to all reservoir types and reservoir characteristics using common injectant gases in both secondary and well as tertiary recovery modes [37]. However, historically, gravity stable (drainage) injections has been applied to highly dipping and reef type reservoirs only.

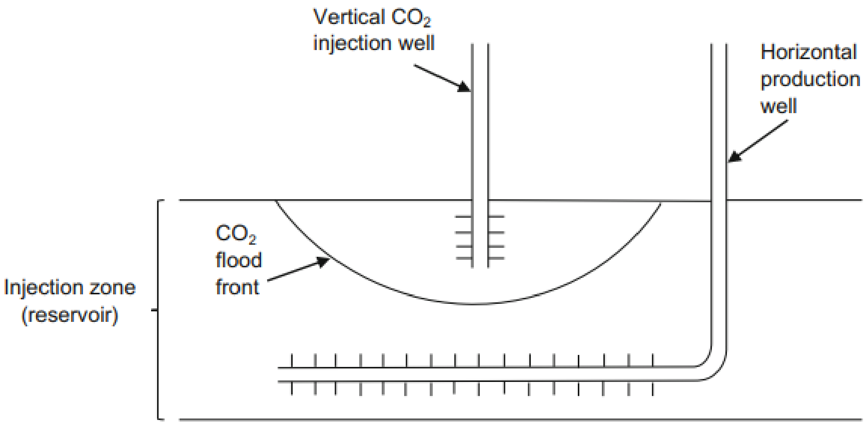

Figure III.2: Schematic of GAGD process [12].

One of the currently operational large-scale simultaneous CO_2-EOR and storage project, namely, the Michigan Basin Project is an excellent example of gravity stable injection in a reef reservoir. However, GAGD injection strategy has not yet caught the full attention of the operators of simultaneous EOR and storage projects.

3.2.2 Formation Water Extraction:

Extraction of the water from the water leg (below the established oil-water contact), if present, for creating additional pore space for injected CO_2 in a simultaneous EOR and storage project also appears to be a good way for enhancing both oil recovery and storage capacity. The numerical modeling studies such as [14] conducted for evaluating the viability of top down miscible CO_2 injection coupled with formation water extraction (Figure III.3) have shown some promise for such alternative injection strategy. However, this strategy needs to be further explored and tested in the field for establishing it as a viable injection strategy.

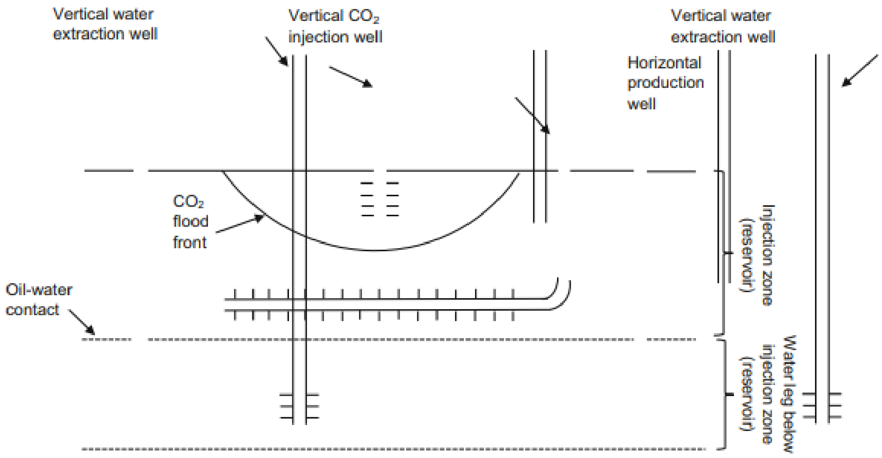

Figure III.3: Schematic of top down continuous CO_2 injection coupled with formation water extraction [12].

3.3 Evaluation of CO_2-Oil Miscibility:

At storage sites of currently operational LSIPs and other large-scale simultaneous CO_2-EOR and storage projects, CO_2 injection (WAG or continuous CO_2 injection) is being done in miscible mode. However, condition of complete miscibility will occur only at a certain pressure, referred as minimum miscibility pressure (MMP). At pressures, lower than MMP, CO_2 and oil may remain immiscible or they just form a partially miscible mixture. The MMP is an important design parameter for assessing the achievement of complete mixing between injected CO_2 and reservoir oil irrespective their relative propositions at the time of mixing at a given location (from injection wellbore to the production wellbore). A reliable estimation of MMP is one of many initial tasks that are performed while designing a simultaneous CO_2-EOR and storage project as an overestimation of MMP can lead to increased operational or facility costs and an underestimation may result in less than expected oil recovery due to achievement of partial miscibility instead of complete miscibility. [14]

At reservoir conditions of pressure and temperature greater than the critical pressure and temperature of CO_2 [7.4 MPa (1068 psi) and 31.1 °C (88 °F)], CO_2 behaves as a supercritical fluid (i.e., exhibiting both liquid-like and gas-like behaviors). These desired pressure and temperature conditions are normally encountered at reservoir depths greater than 2600 ft. The liquid-like behavior (high density) results in high absorption capacity because solubility increases with density, pressure, and temperature, whereas, gas-like behavior (high diffusivity and low viscosity) promotes high mass transfer rate between the solute and solvent. The lower critical (pressure and temperature) parameters of CO_2 allow the tuning of its solvent power at a low energy cost, thus, making it a solvent like no other. [14]

3.3.1 Miscibility Mechanisms:

When injected CO_2 meets the reservoir oil, a continuous mass transfer between the CO_2 and the oil occurs. As, the oil rich CO_2 phase and/or CO_2 rich oil phase move further away from the injection wellbore, they meet increasingly fresh oil to develop a bank of miscible phase which is produced at the production well. Injected CO_2 not only extracts some of the components out of the reservoir oil but some of the injected CO_2 also enters the oil phase. This combination of these two mass transfer mechanisms (mixed or vaporizing-condensing drive) is the most common way in which CO_2 develops the miscibility with reservoir oil (Figure III.4).

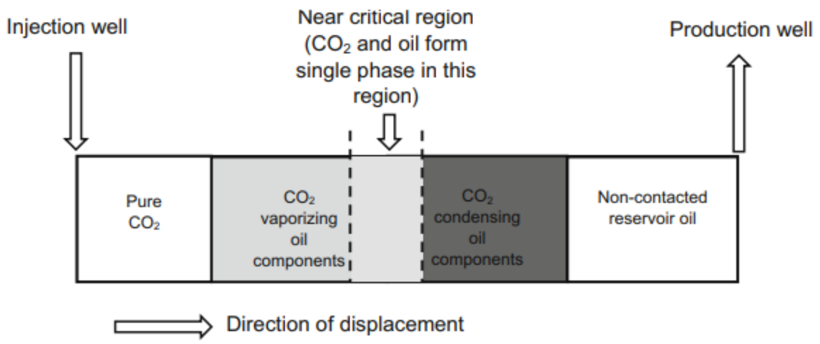

Figure III.4: One dimensional schematic of mixed (vaporizing + condensing) drive mechanism responsible for the development of CO_2-oil miscibility in the reservoir.

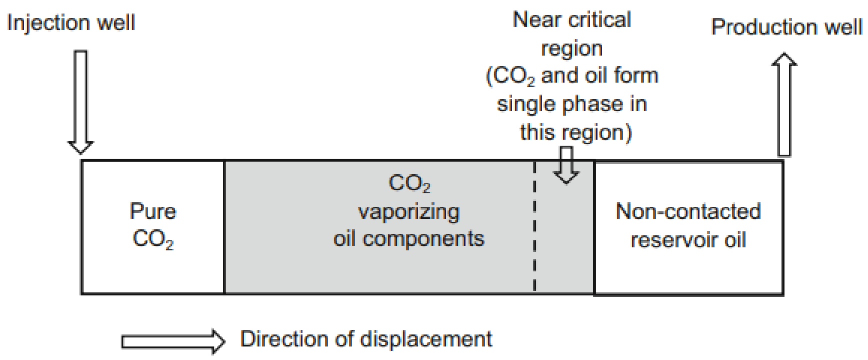

Figure III.5: One dimensional schematic of vaporizing drive mechanism responsible for the development of CO_2-oil miscibility in the reservoir.

In some cases, one mass transfer mechanism (i.e., extraction of the components from the oil phase or vaporizing drive mechanism (Figure III.5) may dominate another mass transfer mechanism (entering of CO_2 into the oil phase or condensing drive mechanism (Figure III.6).

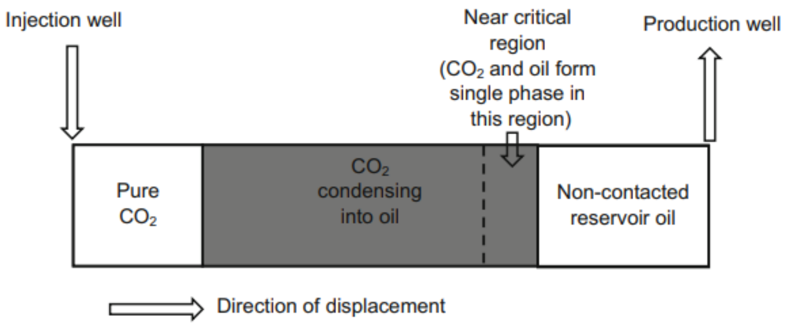

Figure III.6: One dimensional schematic of condensing drive mechanism responsible for the development of CO_2-oil miscibility in the reservoir.

3.3.2 Experimental Techniques for Determining MMP:

Because, an accurate knowledge of MMP is crucial for designing and implementing successful miscible CO_2 injection based EOR and storage projects, operating companies spend significant time and resources to reliably determine the CO_2-oil MMP. Some of the used techniques are:

- ✓ The VIT Technique;
- ✓ Fluorescence-Based Microfluidic Method;
- ✓ rising bubble apparatus (RBA);
- ✓ micro slim-tube test;
- ✓ PVT multi-contact experiments, key tie-line approach and method of characteristics (MOC), vanishing tie-line approach, response surface-based model, and linear gradient theory (LGT) model.

For detailed explanation of the techniques mentioned above, view: [14]

3.4 Maintaining the Integrity of Storage Sites:

Apart from injecting CO_2 in miscible mode, maintaining the integrity of wellbores, injection zone(s), and the overlying seal(s) (caprock(s) is another important engineering aspect that needs to be carefully considered while designing a simultaneous CO_2-EOR and storage project. Before, an injection site can be established as a safe storage site, its ability to confine (i.e., no spill out of the reservoir) the injected CO_2 should also be reconfirmed. [14]

The integrity of storage sites refers to geomechanical properties including in situ horizontal stresses, rock strength (tensile and compressive), stiffness properties [Poisson's ratio and elastic (Young's modulus)], and rock time-dependent deformation properties such as swelling potential, and dynamic properties (compressional wave velocities, shear wave velocity, dynamic Poisson's ratio, and dynamic modulus). The geomechanical properties depend on lithology, pre-existing planes of weakness, regional geomechanical stresses, induced stress resulting from the reservoir fluid withdrawals and external fluids (water, gas and/or CO_2), and coupled geomechanical-chemical processes. [14]

3.4.1 Maintaining the Integrity of Overlying Caprock(s):

According to study published by the International Energy Agency's (IEA) GHG program [48], to form an effective seal (i.e., to prevent vertical migration of injected CO_2 and/or any of the reservoir fluids out of the reservoir), the sealing lithology needs to be impermeable to CO_2, upfaulted and relatively ductile (resistance to fracturing), and laterally continuous while maintaining a consistency of properties over a large area. A detailed treatment of the topic of caprock systems for geologic CO_2 storage can be found it another report [20].

The presence of a thick caprock or several layers of impermeable rocks increases the confidence in its much larger and continuous areal extent compared to relatively thin (i.e., few ft. thick caprock) single caprock. Also, it reduces the possibility of leakage due to capillary (i.e., scenario of capillary entry pressure of the caprock being larger than the buoyance pressure of the stored CO_2) or molecular diffusion effects. Reliable estimation of the thickness of overlying caprock(s), which can be estimated from well logs, drill cuttings, and stratigraphic calculations, is one of the key activities that are carried out in initial site characterization of the potential storage site.

The caprock capillary entry pressure is a function of pore size distribution of caprock, the wetting characteristics of caprock/reservoir fluids/CO_2 system, the density of the injected CO_2 and reservoir fluids (oil, gas, water) and the IFT of CO_2/ reservoir fluids. Laboratory evaluations of capillary entry pressure and molecular diffusion effects, often rare, further ensures the sealing quality of the caprock.

Another key characteristic that makes a caprock an effective caprock(s) is the absence of pre-existing natural fractures and faults. The available seismic surveys, well logs or cores, or outcrop analogs are normally used for verifying the absence of faults in the overlying caprock(s). However, some faults may remain undetected if they fall below the resolution limits of these techniques.

3.4.2 Maintaining the Integrity of Reservoir Rocks:

When fluids are injected into the reservoir rock, an increase in reservoir pore pressure may result in an imbalance of in situ stresses or activation of a fault, which is detrimental for reservoir rock integrity. Similarly, one of the consequences of CO_2 injection in depleted oil fields is the alternation in the in situ thermal and pressure stresses that have potential to impact the mechanical properties of the reservoir rock(s). An alternation in the in-situ stresses (vertical or normal stress and horizontal stresses) resulting from changes in reservoir pore pressure and volume of the reservoir rock can lead to the loss of reservoir and caprock integrity, and the re-activation of existing faults [9].

The reservoir pressurization due to CO_2 injection can also cause vertical expansion of the reservoir which may result in a detectable uplift of ground surface (e.g., In Salah dedicated CO_2 storage project in Algeria), however, the magnitude of uplift will depend on the geometry, geomechanical properties (such as compressibility) of the reservoir and surrounding sediments, and the thickness of the underground reservoir being pressurized at depth [28].

3.4.3 Maintaining the Integrity of Wellbores:

Well integrity means the achievement of fluid containment and pressure containment within the well throughout its whole life cycle [34]. Maintaining the wellbore integrity is critical for the success of simultaneous CO_2 EOR and storage projects because wellbores pose maximum risk of CO_2 migration from the reservoir. Not only, the existing and abandoned wells within the storage site area, that have already penetrated the primary seal (caprock), should be leak free, but also the CO_2 injection wells should also be designed for the long operational lives (often several decades) and even longer (exceeding hundreds to thousands of years) integrity after abandonment.

Wellbore integrity issues are usually divided into two types: improper completion and abandonment of the wells; and the long-term stability of wellbore materials in a CO_2-rich environment [23]. Well integrity can be compromised by defective well completion or as a result of chemical and mechanical stresses that damage the well during the operation or abandonment phases.

A wide range of wellbore completions and abandonments can be encountered in the hydrocarbon extraction and geologic storage projects. However, most often, it is the poor cementing job (i.e., poor mud displacement during cementing job, gas channeling through unset cement) that results in poor cement bonds at cement/reservoir rock, cement/caprock, and cement/casing interfaces, thus, allowing potential for CO_2 leakage through wellbore and corrosion of casing material(s). Stress-induced cracking, formation of micro annuli at the casing-cement interface, incomplete cementing in the annular space or cement degradation can expose the casing to fluids including reservoir brine, injected CO_2, and associated impurities like H_2S and organic acids, thus leading to an increased likelihood of sustained casing pressure (SCP) and casing corrosion.

Thorough evaluation of the cement jobs is acritical for corrosion prediction and protection, as well as assurance of integrity of existing, abandoned, and new wells [58]. However, the well completion records for old wells are hard to find. In such scenarios, sustained annulus pressure (SAP), that is, pressure within the annuli of the well which cannot be reduced to zero by bleeding off [34], can be used for identifying any developed leakage. Daily monitoring and intermittent testing of SAP can be used as an effecting monitoring and warning tool for early detection of well integrity issues. Periodic integrity (pressure testing) of the well, leak testing of wellbore seals (packers, wellhead, and Xmas Tree) as well as chemical analysis of any fluids sampled from well annuli can also assist in maintaining the well integrity.

3.4.4 Strategy for CO_2 Leakage Prevention and Remediation:

- ✓ Selecting favorable storage sites with low risks of CO_2 leakage. Initial characterization of the potential storage sites will assist in identifying a safe and secure site.
- ✓ Identification of all old abandoned wells in the vicinity of storage site, design and installation of injection wells so that they are resistant to CO_2, and proper closure of the storage site are the three key priorities for ensuring the well integrity.
- ✓ Conduct a phased series of formation simulation-based modeling for tracking and predict the location and movement of the CO_2 plume. Modeling results should be calibrated and updated accordingly as more site specific geological and reservoir data become available via drilling of injection and observation wells, and repeat surveys after injection.
- ✓ Install and maintain a comprehensive monitoring system, which is designed as an early warning system of any impeding CO_2 leakage event, and to provide on-going information on the movement and immobilization of the CO_2 plume.
- ✓ Establish a “Ready-to-Use” contingency plan/strategy, should a CO_2 leakage event occur. The plan should contain remediation options for all the most likely leakage scenarios.

Compared to the total cost of a geologic CO_2 storage project, cost associated with the implementations of above-mentioned strategy for remediation of a potential CO_2 leakage event can be considered relatively low, unless a leakage event is of catastrophic nature. Also, use of a prudent approach for maintaining the integrity of the storage site will not only help the industry in increasing the public acceptance of geologic CO_2 storage, but it will also ensure the public safety [21].

4. Conclusion:

The injection of CO2 in reservoirs was primary used for EOR purposes, this led to the CO2 then being trapped inside the reservoir creating an incidental storage, new monitoring software were developed to turn CO2-EOR projects into simultaneous CO2-EOR and storage projects.

Chapter IV:

Study of In Salah CCS project

(Krechba Field).

1. Introduction:

Since Sleipner the first CCS project in 1996, this technology has become a research focus all over the world. The JV therefore decided to adapt this technology and build then the first worldwide project adapting this technique onshore.

The In Salah CCS project is the subject of our study. In this chapter we will assess the effect of the selected reservoir properties, trapping mechanisms, leakage scenarios, on the security of the In Salah CCS project along with recommendations and lessons learned from the project.

2. In Salah CCS project:

The In Salah CCS project is operated by the (JV) between Sonatrach (35%) BP (33.15%) and Statoil (31.85%). It is a developing project with up to 8 gas fields located in the Ahnet-Timmimoun basin, in In Salah in the middle of the Algerian Sahara, it is one of the largest dry gas development projects in the country. Gas is produced, processed and exported from Krechba to Hassi R'Mel (450 KM).

Figure IV.1: map of the In Salah CCS project.

2.1 The Different fields in In Salah

In Salah has 7 fields, where the selection process was carried on, to choose an optimal storage site.

Table IV.1: different fields in In Salah.

Field	year
Teguentour	1957
In Salah Krechba field	1957
Reg	1962
Garet el Befinat	1983
Gour Mahmoud	1988
Hassi Moumene	1990
Boutraa	1999

2.2 Site selection in In Salah:

The development of the In Salah CCS project went through 06 stages: Estimation, site selection, Definition, Execution, Operation and Abandonment. The In Salah project is currently in the abandonment stage.

In the site selection stage, 06 choices for the storage of CO_2 were taken into consideration and subsequently were a subject of a risk and cost assessment:

1) The Devonian field of Krechba D30.
2) The Carboniferous field of Krechba C10.2.
3) The Continental aquifer.
4) The Depleted Hassi R'Mel Gas Field.
5) The deep saline aquifer of Hassi R'Mel.
6) The Hassi Messaoud field, for enhanced oil recovery (EOR).

The choice was made for the Krechba Carboniferous reservoir, which was defined along with several options evaluated during the "Defining" stage. The option chosen for the "Execution" is compression and dehydration at the Central Processing Facility (CPF), with two pipelines 10km long and 8 "in diameter dedicated CO_2 transport. And with three injection wells drilled horizontally in the Carboniferous saline aquifer of Krechba. CO_2 is then injected into the Krechba aquifer through these 03 injection wells for long-term storage purposes as an initiative for the reduction of greenhouse gases. Among the criteria for selecting Krechba carboniferous as a favorable storage site, we mention:

1) Krechba is a place considered inactive from a seismic point of view.
2) 900m of caprock, ensuring an excellent seal capacity, therefore a safe trapping of CO_2.
3) Carboniferous caprock has successfully trapped natural gas for millions of years, theoretically, it would do the same goes for CO_2.
4) The distance between Krechba and the population areas is important (minimal danger to human life in the case of a leak).

3. Presentation of Krechba field:

3.1 Reservoir properties:

After choosing Krechba as a storage site here are some of the reservoir properties that we need to take into consideration in the next steps of the project.

Carboniferous:	**C10.2**
Hauteur [m]:	**20-25**
Porosity [%]:	**19**
Compressibility [10-6 psi-1]:	**3,5762**

Temperature [°C]:	**200,7**
Initial pressure [Psia]:	**2531,5**
GWC[m]:	**1780m**

3.2 Geography:

Krechba reservoir is located in the northern part, 70 km north of the Teg field. This field was discovered in 1958 with 9 exploration wells and 9 development wells have been drilled. There are also 3 horizontal wells that have been drilled for the geological storage of CO_2. During the exploration and appraisal phase, a 3D seismic study was acquired for the entire reservoir in 1997.

3.3 Geology:

The Krechba reservoir appears as a large, structurally simple, closed anticlinal structure. There are two serial gas fields: the Carboniferous C10.2 sand-sandstone and the Devonian sand-sandstone.

The current architecture of the Krechba reservoir was modeled at the end of the Carboniferous during the "Hercynian Orogeny". It is an anticline that developed as a result of deep compression in the plinth. These were accompanied by a network of north-south faults intersecting the west of the reservoir. The location of the paleovallée, in which the Tournaisian sandstones were deposited, was very likely influenced by these faults.

3.4 The Carboniferous:

The carboniferous sandstone layer is found at a depth of 1700m, which was deposited on an ancient valley. The carboniferous sandstones are of a good quality, with a porosity ranging up to 22% and a horizontal-permeability (kh) up to 600 mDm. The water level (Free water level FWL) in the carboniferous layer is at 1330m giving a regional fence of 130K_{m2} with a maximum vertical column of 70m. This water was confirmed by pressure measurements and recorded tests.

3.5 The Devonian:

The Devonian reservoir lies at a depth ranging from 2850 to 3350m and includes a variety of crowded sandstone, separated by clay. These sandstones are of "shallow marine" to "marginal marine" origin. The Gedinnian sandstone layers (D30 to D10) are laterally extensive and have moderate quality, with a porosity up to 15% and a horizontal permeability up to 600mD.m. The Siegenian sandstones (D40) are of poorer quality due to diagenesis; the porosities are generally less than 10%.

3.6 Krechba seismic:

A 3D seismic was acquired in 1997 to map the reservoir. The main goal of this processing was to improve the signal quality and the resolution of the seismic, and to improve the imagery of The Overburden Section, mainly based on the Devonian. New interpretations were therefore generated for the two reservoirs; Carboniferous and Devonian from improved seismic.

3.7 Results of the 2009 seismic:

1) 14 horizons were interpreted during this seismic, from the Ordovician to the Cretaceous aquifer.
2) 3 fault groups have been interpreted: Ordovician, Devonian and Carboniferous.
   - The Carboniferous faults are on a small scale, with limited offset and variable orientations: which crosses the C20.1.
   - No large-scale faults that cross the caprock: Small scale faults and fractures may exist.

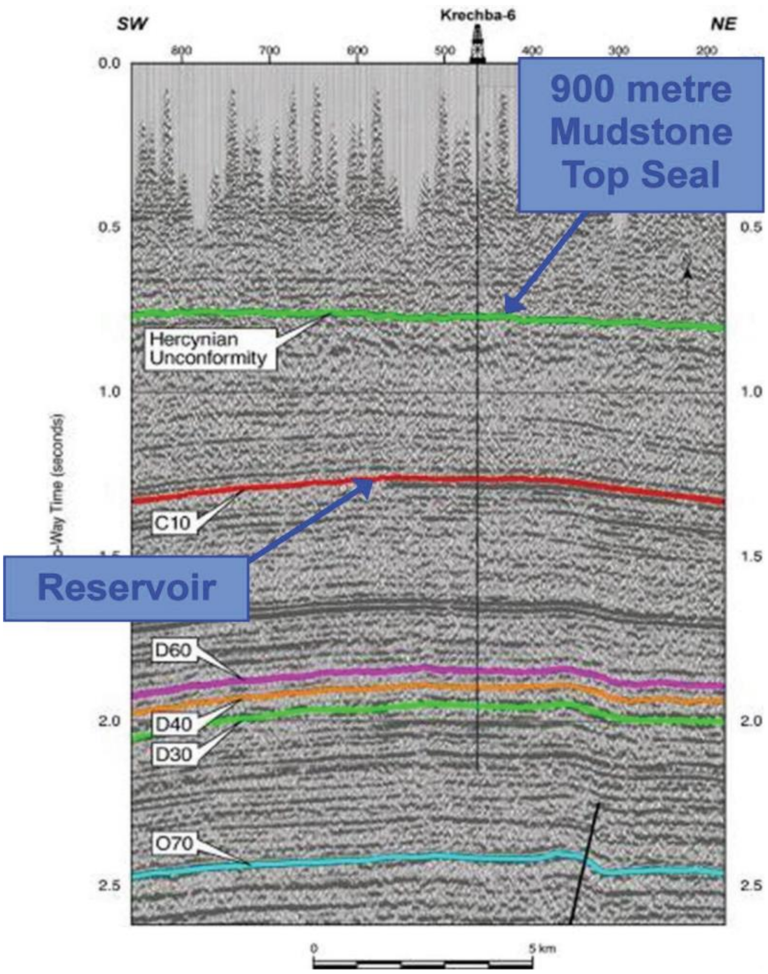

Figure IV.2: Pre-treatment seismic results, illustrating the carboniferous reservoir and the top of the caprock.

3.8 Wells in Krechba:

Krechba includes a total of 28 wells, (figure IV.3) is a distribution of these different wells on a satellite image of the Krechba field. The table below resumes all the wells and their function.

Figure IV.3: Satellite image of the Krechba field, well distribution.

Table IV.2: resumes the different wells of Krechba.

Well type	**Well name**	**Well function**
CO_2 injection wells	**Kb-501** **Kb-502** **Kb-503**	Horizontal CO_2 injection wells
Gas production wells	**Kb-11** **Kb-12** **Kb-13** **Kb-14** **Kb-15**	Horizontal gas production wells (90% methane).
	Kb-6 **Kb-16** **Kb-17**	Vertical gas production wells
Monitoring wells	**Kb-9**	Observation of any CO_2 leak
	Kb-601 **Kb-602** **Kb-603** **Kb-604** **Kb-605**	Monitoring of groundwater and water sampling to check its salinity
Abandoned wells	**Kb-1** **Kb-2** **Kb-3** **Kb-4** **Kb-5** **Kb-7** **Kb-8** **Kb-10**	Mostly drilled in the 80's for exploration and operation goals (all of them are abandoned).

4. CCS processes in Krechba:

4.1 CO_2 capture:

In In Salah, CO_2 is captured from the natural gas produced, the process itself is analogous to the post-combustion process used to capture CO_2 from the flue gases produced by the combustion, because here (and as for all gas fields containing a high dose of acid gases), CO_2 does not result from combustion, but exists naturally in the dry gas produced.

4.2 CO_2 Injection:

Three horizontal injection wells were operated to inject CO_2 into the Krechba aquifer, with a length ranging from 1500 to 1800m, with an injection rate of 50 mmscfd, they were drilled using "Geosteering Technology" in order to maintain the well inside the thin injection layer during drilling, that is to stay perpendicular to the orientation of the dominant fracture to maximize injection capacity.

About 1.4 million standard cubic meters per day of CO_2 are obtained from processing the produced gas in Krechba. Before being reinjected into the reservoir, it is compressed at 185 Bars, a very high pressure to force it into low permeability sandstone reservoirs. About 1mT of CO_2 is injected each year.

4.3 CO_2 storage:

After capture and transport CO_2 is injected into the deep saline aquifer of the Krechba Carboniferous C10 reservoir, just below the simultaneously produced gas phase. This sandstone reservoir is characterized by a low porosity of (13-20%) and low permeability (10mD), and a thickness of 20 m. The injection depth is between 1850 and 1950 m underground.

These characteristics are close to those of many other deep saline aquifers which are now candidates for CCS projects around the world. The sealing of the reservoir is ensured by the presence of a clay caprock of carboniferous C10.3 with a thickness of 950 m surmounted by 900 m of a sandstone and clay layer of the Cretaceous which contains the aquifer of drinking water of the continental intercalary aquifer (see figure IV.4).

Throughout the life of the CCS project in Krechba, it is planned to store up to 17 million tons of CO_2. Until then, around 3.9 million tons of CO_2 have been injected mainly by two wells in north KB-502and KB-503.

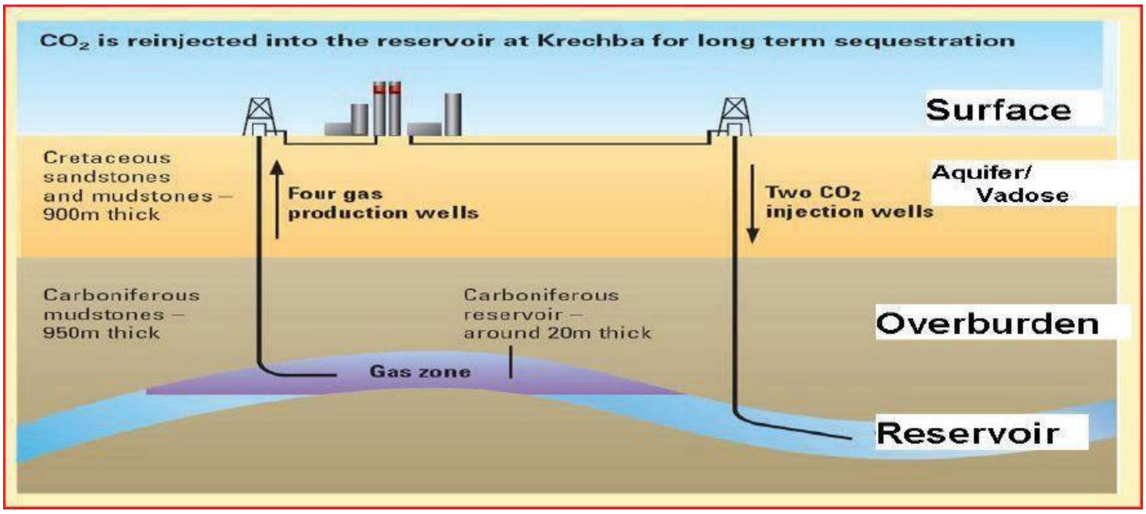

Figure IV.4: Representative figure of the CO_2 storage formation.

4.4 Trapping mechanisms in Krechba:

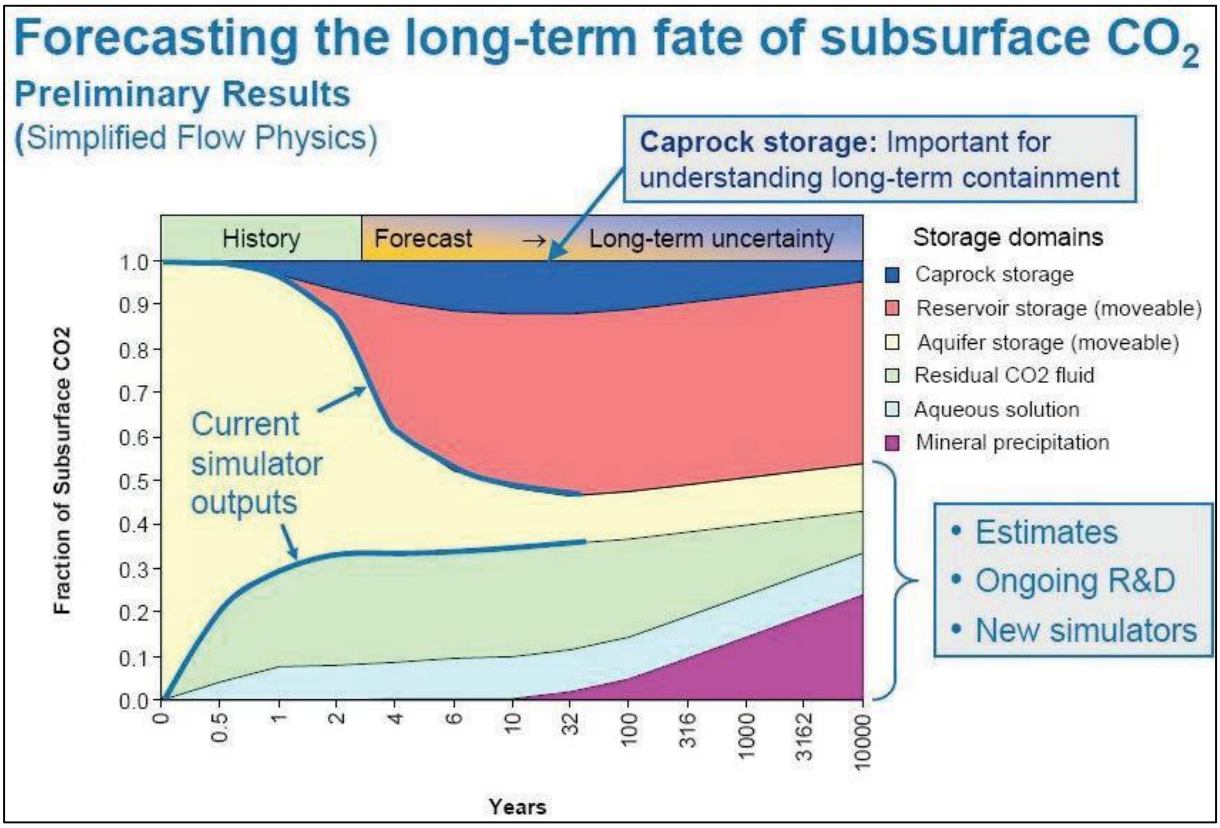

Figure IV.5: Representative diagram of the trapping mechanisms predicted for CO_2 sequestration in Krechba in over time, based on the history of injection up to early 2007.

Interpretation and observation:

(Figure IV.5) above represents the predictions of the trapping mode of CO_2 in the aquifer of Krechba as a function of time. First the CO_2 pushes and displaces the surrounding water (Drainage). And since the mobility ratio of CO_2 is greater than that of formation water, a Channeling phenomenon occurs.

It was noted that at the start of the injection and around the injection wells, CO_2 was in its supercritical state but still mobile freely in the aquifer. The aim was to have the maximum amount of CO_2 dissolved in the aquifer, but this takes time, and requires stabilization of both fluids. But since the injection was still on continuously, it will take a little time and yet not all the CO_2 will be dissolved. This is explained by the saturation of saline water with CO_2. It is known that the relationship between CO_2 dissolution and the aquifer's salinity is an inverse relationship (See chapter II).

Obviously, CO_2 in its supercritical state is less dense than the formation water, so it migrates to the Caprock through buoyancy. This is how most of the injected CO_2, and even after decades after his injection, is found trapped by the Caprock, or mobile in the reservoir.

5. Krechba's CCS project monitoring:

Active surveillance of the sequestration site in the short term, using multidisciplinary skills, is essential to ensure sequestration long-term CO_2 security.

A full range of surveillance techniques has been used over the first five years to monitor CO_2 sequestration in In Salah, such as geochemical, geophysical technologies, 3D and 4D seismic and satellite imagery. These monitoring techniques are used to assess:

- CO_2 plume Migration.
- Well integrity.
- Caprock integrity.
- Pressure evolution over time.

5.1 JIP Monitoring program:

Recognizing the importance of the role that In Salah could play in promoting a secure and economical sequestration of CO_2, gas operators have set up a project at the international level (JIP, Joint Industry Project) in 2005. Before starting the CO_2 injection, risks of a leak have been assessed, so a monitoring program company was appointed to assess the most probable risks by the JV itself. The JIP has established a program to monitor CO_2 migration to verify and ensure long-term CO_2 sequestration within the Krechba Carboniferous. The monitoring program went through 3 phases:

- Pre-injection monitoring;
- Monitoring during the injection;
- Post injection monitoring (not performed).

The following table resumes all the monitoring techniques along with the objective of each technique.

Table IV.3: Main monitoring technologies for geological CO_2 storage sites

Monitoring technology	Objective	Action
Wellhead and annulus samplings	• Well integrity status • CO_2 plume migration	• Two samples per month since 2005
CO_2 Trackers	• CO_2 plume migration.	• Since 2006
Loggings and wireline samplings	• Formations characteristics and properties.	• Higher formations samplings • Development wells loggings
Soil gas/surface flux.	• CO_2 leak on the surface	• Pre-injection survey on 2004. • Another one on 2009
3D/4D seismic.	• CO_2 plume migration.	• Initial Survey on 1997 • High resolution survey on 2009
Deep observation wells	• CO_2 plume migration.	/
Micro-seismic	• Caprock integrity status	• A testing well drilled on mid-2009 near Kb-502 • 50 geophones are installed at depth of 500m-1500m above the injection area).
Electromagnetic surface and wellbore.	• CO_2 plume migration	• Not useful in Krechba because wells were too far apart
VSP	• Caprock integrity status • CO_2 plum migration • Fractures evaluation	• Modeling results not conclusive. • Decision depends on 3D VSP with micro-seismic.
Micro-biology.	• CO_2 leak on the surface	• First sample on 2009
InSAR monitoring.	• Caprock integrity status • CO_2 plume migration • Pressure evolution	• Widely used, catch image every 28 days.

5.2 Different Monitoring results:

5.2.1 *InSAR, Satellite Imagery:*

An Uplift of the adjacent land surface of the three CO_2 injection wells was detected with subsidence observed around gas producing wells in Krechba. The results obtained during the first years of injection indicates that the soil elevated up to 10mm / year. (See annex)

5.2.2 Fluid Sampling, wellhead pressure samplings:

In 2007, huge concentrations of CO_2 were detected in the Kb-5 well (1.4 Km North West of the Kb-502 injector well).

Analysis of the injected CO_2 tracer confirms that the detected CO_2 comes from the Kb-502 well. It has been closed and Kb-5 was successfully abandoned by plugging operations. And the injection was resumed on November 2009 until the end of 2011. Soil monitoring is conducted around this well in order to monitor any leak in the surface.

6. Summary of the CO_2 breakthrough at the Kb-5 well:

In June 29th, 2007 a leak was detected on the KB-5 wellhead by a military group, the JV immediately stopped the leak. The volume of leaked CO_2 was estimated at less than one ton, while the injected volume is 1 million tons. [51]

6.1 Presentation and history of Kb-5:

Kb-5 is a former Sonatrach well, designed for exploration purposes. Drilled in 1980 by Forex SHDP Super 20n at depth of: 3415 m. This well is located 10 km north of Krechba CPF.

The well was abandoned by Sonatrach in October 18, 1980 with three class G cement plugs. From 3415 to 3210m (B1), 3200 to 2980 (B2) m and the third from 2850 to 2746m (B3), passing through The Casing Shoe at 2800m and a Bridge Plug at 2703m (B4). (see Annex 1)

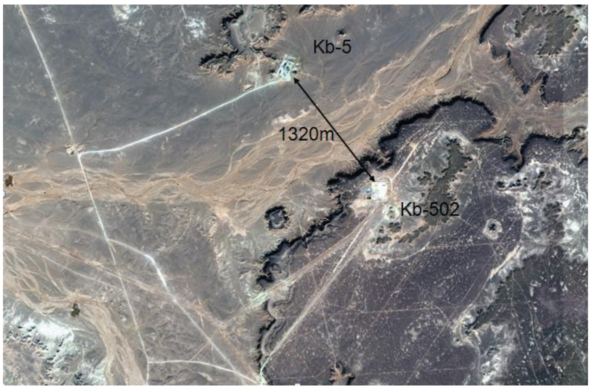

Figure IV.6: Location of Kb-5 to Kb-502, on a satellite image of Krechba.

Note that the initial state of abandonment of Kb-5 did not isolate the carboniferous layer. Because of the cementing policy in Algeria, it was forbidden to cement near the aquifer. The carboniferous reservoir C10.2 is at 1778 m.

6.2 Basic theoretical investigation of KB-5 leak:

Under certain circumstances, wells passing through the caprock may prevent the CO_2 migration to the surface, but only if they are perfectly cemented and have efficient plug "Properly Cemented and Plugged", which is not always the case, because the cement or the plug may prove to be inefficient mechanically or due to corrosion, if this integrity was compromised the well can be a high-permeability pipe through which, CO_2 can escape. Three different scenarios may occur: [57]

- Cement degradation by CO_2;
- Corrosion of casing by the presence of CO_2;
- Corrosion of casing by the presence of CO_2.

The following (figure IV.7) will briefly demonstrate those 3 scenarios:

Approaching Kb-5, the CO_2 was not dissolved in the saline water, this is confirmed by the fact that the solubility of CO_2 decreases due to the pressure drop in the vicinity of the well, and because of the relatively high salinity of Krechba aquifer (this water quickly saturates) .We think then that the CO_2 would present itself mostly in the form of supercritical bubbles moving faster than water.

Therefore, we believe, that under these turbulent dynamic conditions (in the vicinity of the well), and given the instability of the CO_2 / water interface, it is unlikely that this CO_2 could have dissolved to subsequently form carbonic acid and thereby cause corrosion.

During our investigation a clue ended up appearing which can support the hypothesis of carbonic acid formation and that it may have caused (or accelerated) the casing corrosion or cement damage. It is about the presence of void “annulus” between the formation and the $9^{5/8}$ casing, an annular space that begins at the depth of 1732m at the Muleshoe of the $13^{3/8}$ casing up to the DV at 1680m

We believe that supercritical CO_2, once arrived at Kb-5 may have entered and accumulated in this annular space - which initially contained water (figure IV.8), a CO_2 / water interface was able to stabilize, thus causing the phenomena of CO_2 dissolution.

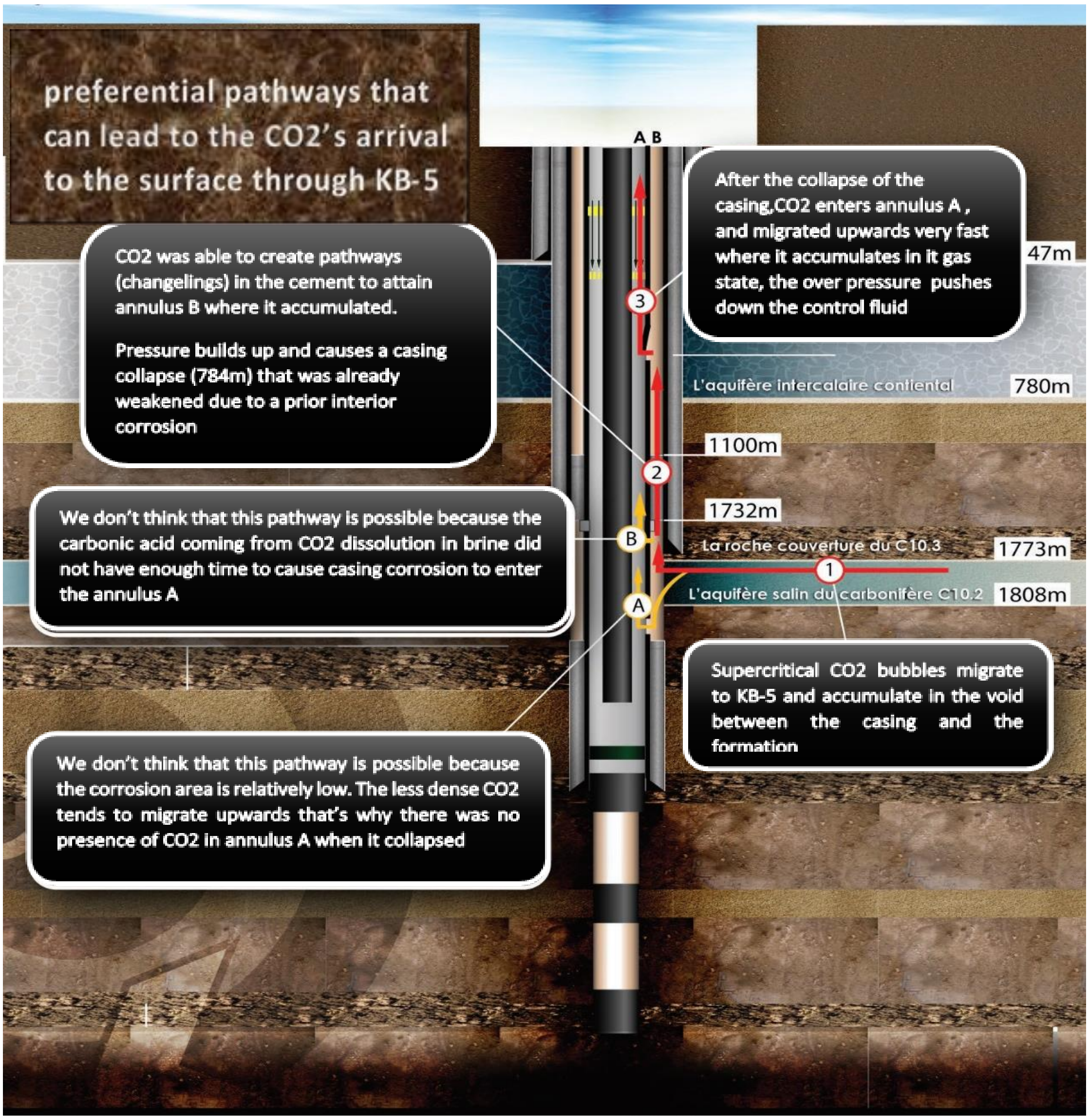

Figure IV.7: preferential pathways for CO_2 leakage to the surface through KB-5

Figure IV.8: Supercritical CO_2 accumulates in the casing / formation annulus.

6.3 Investigation results:

We deduct based on:

- Surface observations during abandonment operations.
- The theoretical basis for the action of CO_2 on casing and cement.

We can summarize the scenario which seemed to us the most probable by the succession of these events:

1) The $9^{5/8}$ casing was already corroded in the aquifer long before the arrival of CO_2, and this under the effect of corrosive action of salty and acidic aquifer water.
2) This corrosion created communications between the aquifer and the annular space A.
3) These connections between the aquifer water and the neutralization brine were consequence of the acidification of the latter.
4) The neutralization brine (contained in the casing) once it has become acidic deteriorates the mechanical properties of steel through the effect of corrosion.
5) The CO_2 arrives between 2005 and 2006 at Kb-5, it accumulates in the annular vacuum between the casing and the formation.
6) The supercritical CO_2 reacts with the minerals contained in the cement, it leads to its degrading and cracking.
7) Despite the stabilization of the CO_2 / water interface in the casing / formation area, the carbonic acid did not have enough time to cause perforations. Therefore, it did not enter the annulus A through this path.
8) The CO_2 migrates through the channels of the cement to reach annulus B.
9) The gaseous CO_2 accumulates there, the annular pressure B increases and causes the collapse of the casing already weakened from the inside by the corrosive action of the brine which has become acidic. [26]

6.4 Effect of KB-5 leakage on the security and efficiency of CO_2 storage:

The CO_2 leak in Kb-5 raised many questions about the efficiency of CO_2 storage Krechba, this major event in the history of the Krechba CCS project has emerged as proof that the CO_2 stored in Krechba can end up on the surface and why not contaminate the continental intercalary aquifer.

7. Presence of fractures in Krechba:

The existence of significant fractures in the Carboniferous reservoir of Krechba was by no means possible, the proof, this reservoir was selected to be a permanent CO_2 storage site among seven other candidate this purpose (See **Site selection in In Salah).**

However, during the drilling of horizontal injection wells in 2002, the presence of certain fractures was confirmed by:

- Drilling mud loss;
- Imaging Logging (IMF) (resistivity measurement);
- Core sampling;
- 3D seismic data.

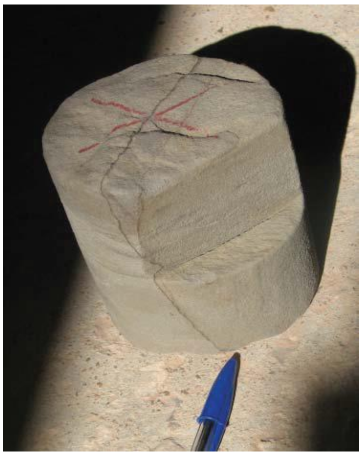

Figure IV.9: Example of a fracture present in a core extracted from a production well in Krechba.

2009 seismic results suggested the existence of fractures in the direction NW-SE, as well as a probable fracture is possible which lies in the direction of Kb-502 - Kb-5

7.1 Investigating the presence of the Kb-502- Kb-5 fracture:

As mentioned above (monitoring results) the leak of CO_2 in Kb-5 came from the CO_2 injected in Kb-502 (Analysis of the CO_2 Tracer). Injection into Kb-502 did not begin until mid-2005. The leak at Kb-5 is observed on August 2006, just a few months after the start of the injection. The CO_2 injection pressure cannot be the reason of rock fracturing, but it is possible to induce the opening and development of a pre-existing inactive fracture.

7.2 Fracture Simulation:

In this study, we used the JV simulation model as a reference model. And it was proposed to predict on the migration of CO_2 plume from Kb-502 injection well, two basic scenarios were executed, one assuming a reservoir with the same characteristics, same permeability in particular, and a second assuming the presence of a fracture along the path between Kb-502 and Kb-5. So, we assigned a high permeability (500 - 1000 and 2000mD) to the fracture which connects both wells Kb-502, Kb-5.

Below, we present the results of these two simulations; the first without fracture, and the second with fracture (1000mD in this case).

7.3 Results of the Simulation:

7.3.1 1st Scenario (no fracture):

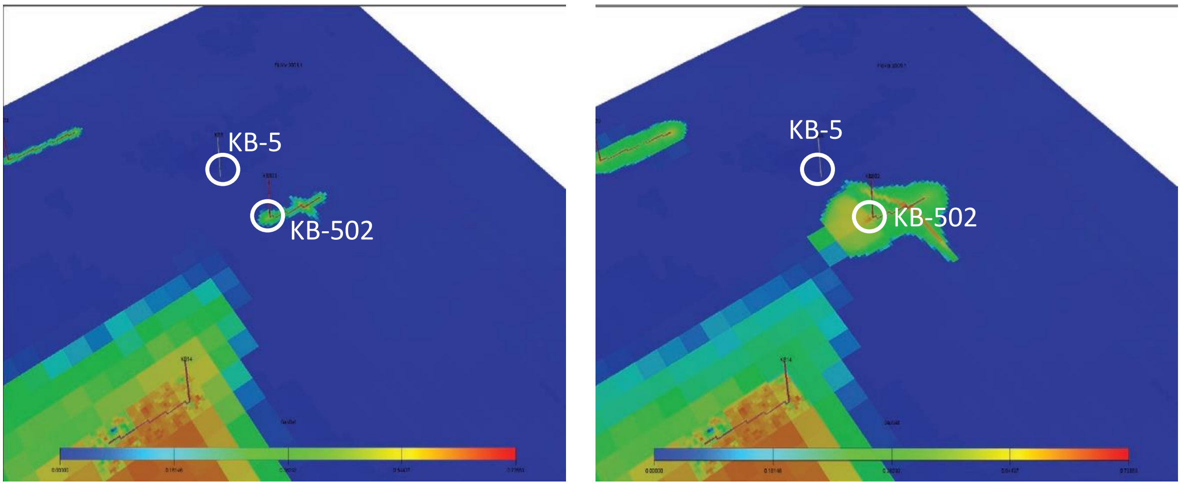

Figure IV.10: Results of the simulation of the distribution of gas (CO_2) in the reservoir of Krechba, 2006-2010. "Model without fracture Kb-502, Kb-5"

The migration of CO_2 around Kb-502 is more or less homogeneous and its displacement has moderate speed. We notice that after 5 years the CO_2 still does not reach Kb-5. This allows us to say with certainty that there must be a preferential path with higher permeability connecting both wells Kb-502, Kb-5.

7.3.2 2nd Scenario (with fracture):

When high permeability has been applied to the reservoir (Shown on Figure IV.1 below), we see that after one year of injection, the CO_2 migrates and reaches the around the Kb-5 well. From this simple simulation we can say that the fracture is the only explanation of the fast arrival of CO_2 plume to Kb-5.

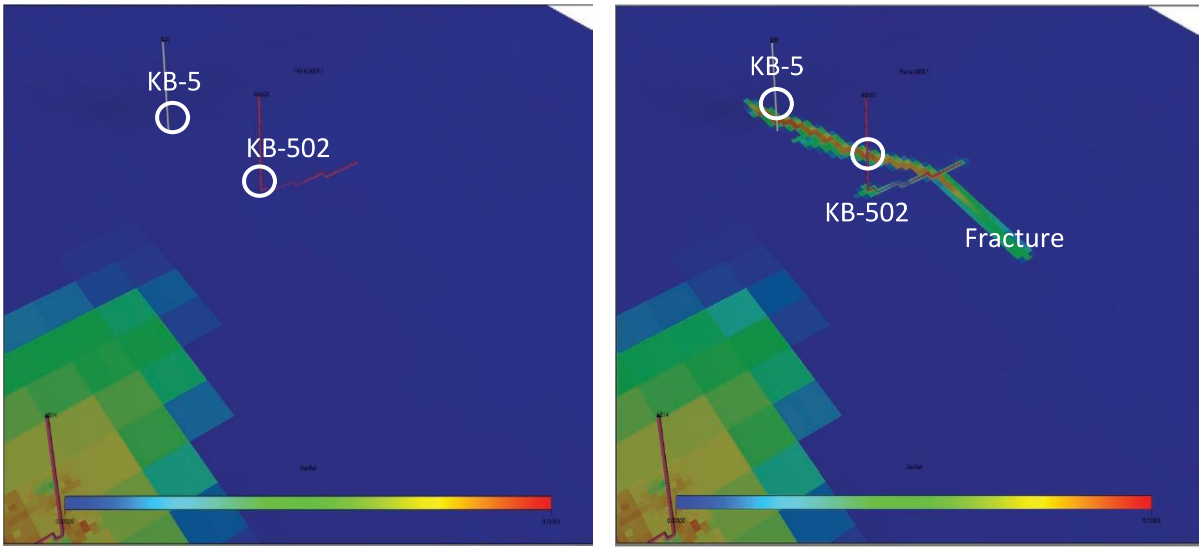

Figure IV.11: simulation results of the distribution of CO_2 in the Krechba, between 2005 and 2006 "Model with fracture Kb-502, Kb-5, Fracture permeability = 1000mD”

Simulation data interpretations demonstrate the following:

- The presence of a significant fracture (high permeability path) connecting the two wells Kb-502 and Kb-5.
- The characteristics of this fracture that can be drawn so far are: the permeability which is around 1000mD.
- The extension of this fracture: This fracture extends less between the two Kb-502 wells and Kb-5, a distance of approximately 1.4 km.

7.4 Behavior of the fracture between Kb-502, Kb-5:

7.4.1 Did the fracture react with CO_2 injection?

If we take the results of the History Matching of the simulation model, we notice the impossibility of converging the simulated pressure towards the real bottom whole pressures (BHP) throughout the injection lifetime (2005 to 2011) without going through a change in the reservoir’s characteristics. Indeed, in (Figure IV.1) below, the model does not converge in the first period (Start of injection) (Zone 2). Because if we try to make it converge in this period (2005 and 2009) the model does not converge in the other periods (Zone 3).

This inability to make the model consistent throughout the injection lifetime is explained by the fact that the parameters of the reservoir change during the injection. This can be translated by the existence of two injection regimes; One at the start of the injection (2005, 2009) (Zone 2) and the other after a few months of injection (Zone 3),

This change concerns the fracture connecting both wells Kb-502, Kb-5, whose parameters (its behavior) changes during the injection; that means this fracture opens and closes. This point can be deduced from the fact that at the start and the stop of injection, the data acquired from the well and their analyzes, show that the fracture connecting the two wells has the same properties of the reservoir, means it was closed at the beginning, expanded with the injection and reclosed after suspending the injection for two years.

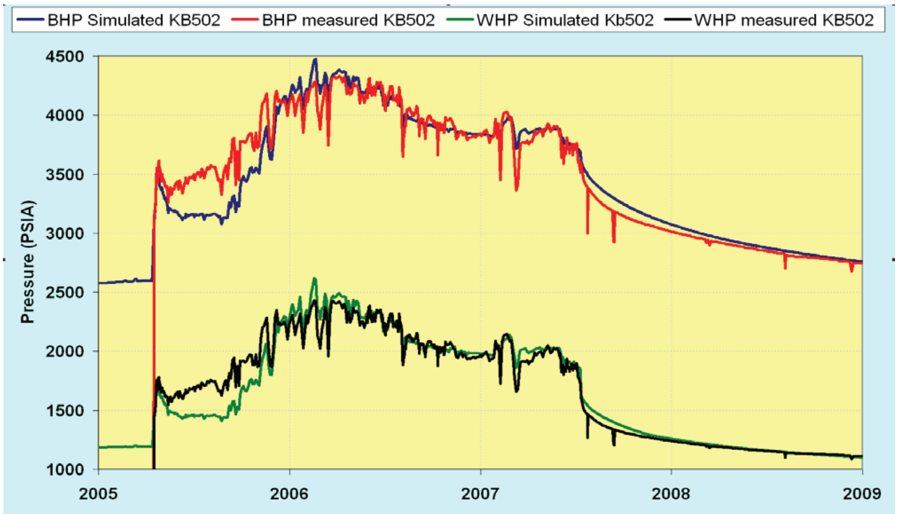

Figure IV.12: Diagram illustrating the History Matching of the simulation model with the variation of bottom pressure.

7.4.2 State of integrity of the Caprock and Position of the fracture Kb-502, Kb-5 on the efficiency of CO_2 storage in Krechba:

Research conducted by experts to simulate this fracture and make the model consistent with the results found by InSAR satellite imagery, show that it is impossible to have both CO_2 diffusion lobes in the reservoir with a fracture along the Carboniferous C10.2 only having a thickness of only 20 to 25m. Only the extension of this fracture about 100 to 200m through the Caprock can give these results.

However, the results the continental intercalary aquifer sampling carried out between Kb-502 and Kb-5, shows no trace of CO_2. This says the fracture does not extend over the entire Caprock which is 950m.

The existing fracture between both wells is considered positive under the prospect of improving the injectivity index, and therefore the injection capacity. However, it must be defined if this fracture can put into question the security and efficiency of the Storage geological CO_2 in Krechba.

The failure of the Caprock seal makes the effectiveness of the Geological storage of CO_2 in Krechba questionable. This failure may be the cause of a possible leak in the surface, therefore danger of suffocation, danger of contamination of drinking water.

On the other hand, a monitoring program has been adapted according to its new data, to provide greater efficiency. As a result, we have stepped up monitoring of the drinking water aquifer by sampling and laboratory analysis, a new monitoring method is implemented to monitor CO_2 on the surface, it was implementing gas tracers 20cm underground and cover a large area, and then analyze them in the laboratory to verify the existence of CO_2. [17]

8. Conclusion:

1. The dominant trapping mechanism in Krechba field is structural trapping where the CO_2 is floating freely in its supercritical state under the caprock, where it is the only barrier that goes against CO_2 migration to the surface.
2. CO_2 free floatability under the caprock was the form of movement from the injection well KB-502 to the abandoned well KB-5, where a leak of important amounts of CO_2 accrued.
3. The incidental leak in KB-5 led to a series of additional investigations, where a fracture was discovered. the whole project was suspended until further studies on the fracture
4. The premature arrival of CO_2 was led by a fracture connecting KB-502 and KB-5.
5. Even if the fracture did not expand and open because of the injection, the arrival of CO_2 plume to KB-5 was certain after 5 years (according to simulations). Knowing that 5 years is not enough for a complete solubility of the all the injected amounts of CO_2. That means the leak at KB-5 was inevitable unless the well integrity was insured and maintained in the first place.
6. The caprock integrity became questionable since the fracture expends along with the injection of CO_2. Yet there was no proving evidence of the effect of this fracture on the security of the storage.

General Conclusion:

Carbon capture and storage seems to be one of the most promising technologies to mitigate the greenhouse gases yet it’s still in a study and a development phase.

The adoption of this technology in Algeria was a great step for its petroleum industry and if it went as planned it would add a value to the environmental development of Algeria’s petroleum industry.

Site selection and maintaining site integrity are the most limiting processes of the success of any large scale yet delicate CCS project.

Talking from a legal aspect, fractured reservoirs are not a suitable storage site because of what it can lead to. From polluting nearby drinking sources, to huge surface CO_2 leak, which go against the main objective of CO_2 CCS. And talking from an engineering aspect, many studies conducted by researches proved the inefficiency of injecting CO_2 in fractured reservoirs because of the impossibility of maintaining it trapped underground. These studies showed that the amount of leaked or produced CO_2 is almost equal to the amount of injected CO_2, in other words the amount of stored (trapped) CO_2 Was too little compared to the aimed stored amount. This is the effect of fractures on the storage capacity and security which is the first criteria to be taken into consideration during site selection and characterization.

The bad drilling cement jobs in wells are a prime factor and issue in CO_2 storage in onshore storage sites, this issue can affect all kinds of wells and can cause a major problem such as hydraulic communications that lead to corrosion and leakage, as such a prime example of this issue is seen in In Salah CCS project, Krechba field, KB-5 well. This problem is not given enough attention in previous studies, but since the leakage event in In Salah, maintaining wellbores integrity strategies have taken place in all CCS project.

Recommendations:

In a CCS projects, a set of trapping mechanisms take place to ensure that the injected CO_2 stays trapped for the longest period of time that can reach up to millions of years, we state them from the least to the most secure:

Hydrodynamical trapping < residual trapping <solubility trapping <mineral trapping.

We can attain all these mechanisms in one injection project. It all depends on for how long did the CO_2 stayed underground (i.e. For the first 5-10 years hydrodynamical and residual tapping occur, then in the first century we attain solubility trapping and so on). For example: The dominant trapping mechanism in Krechba was the hydrodynamical trapping (Where CO_2 was mobile in the aquifer trapped under the caprock).to attain more secure mechanisms (solubility), more time was required. But due to the leakage event, the project stopped before it hit it's first decade. Therefore, there was no enough time to achieve an efficient trapping mechanism for such a large amount of stored CO_2.

Before any site selection process, potential leakage mechanisms or scenarios should be taken into consideration such as leakage through old abandoned wells (erosion of well completion or poorly cemented wells) or through existing faults and fractures. By using a complete risk assessment, we can predict the level of security of any CCS project.

Site selection requires updated data obtained from the newest available technologies. A site is selected based on it's sealing capacity, storage capacity, injectivity, trapping mechanisms and its cost. If a site fits all the mentioned above criteria, further studies on its reservoir properties should be carried on. Its pressure, permeability, porosity, temperature, and salinity should be coupled with a geomechanical model to know the behavior of the reservoir towards the injection, and a CO_2 flow model to know the CO_2 behavior in the reservoir.

However, the presence of fractures is the decisive criteria during the selection process i.e. even if the site fits all the criteria it is still not chosen until proving that it is not naturally fractured. Because choosing a reservoir with existing fractures be it active or inactive goes against injection policies, due to the major risk of CO_2 migration to surface or to nearby drinking water sources through those fractures.

Due the KB-5 leakage event, it became necessary to carry out a large program of reassessment of completion state (well integrity tests) of all wells in general, and abandoned wells in particular, to prevent from now on any subsequent risks of a CO_2 leak to the surface.

The primary study of Krechba field didn't detect any fractures because they used old seismic data, but we believe that additional inspection and more improved technologies (microcosmic and core analysis) should've taken place during the first phase or reservoir characterization to detect the inactive fracture, and therefore, perform further studies on the behavior of the fracture (injectivity tests). Then, design an injection strategy that doesn't lead to the activation (reopen) of the fracture.

In our case (Krechba field) the injection of a huge amount of CO_2 was limited to three wells only, that led to a fracture reopen due to great injectivity rates. Therefore, we think that more injection wells should have been drilled to reduce the charge on other injection wells. At the same time, turning the abandoned wells into injection wells should have been considered regardless of the cost. This is to avoid any potential leakage from abandoned wells because of their questionable wellbore integrity,

Injection strategies, rates and pressures need to be linked to detailed geomechanical models of the reservoir and the overburden. Early acquisition of geomechanical data in the reservoir and overburden, including extended leak-off tests, is advisable.

Regular Risk Assessments should be conducted to inform the on-going operational and monitoring strategies.

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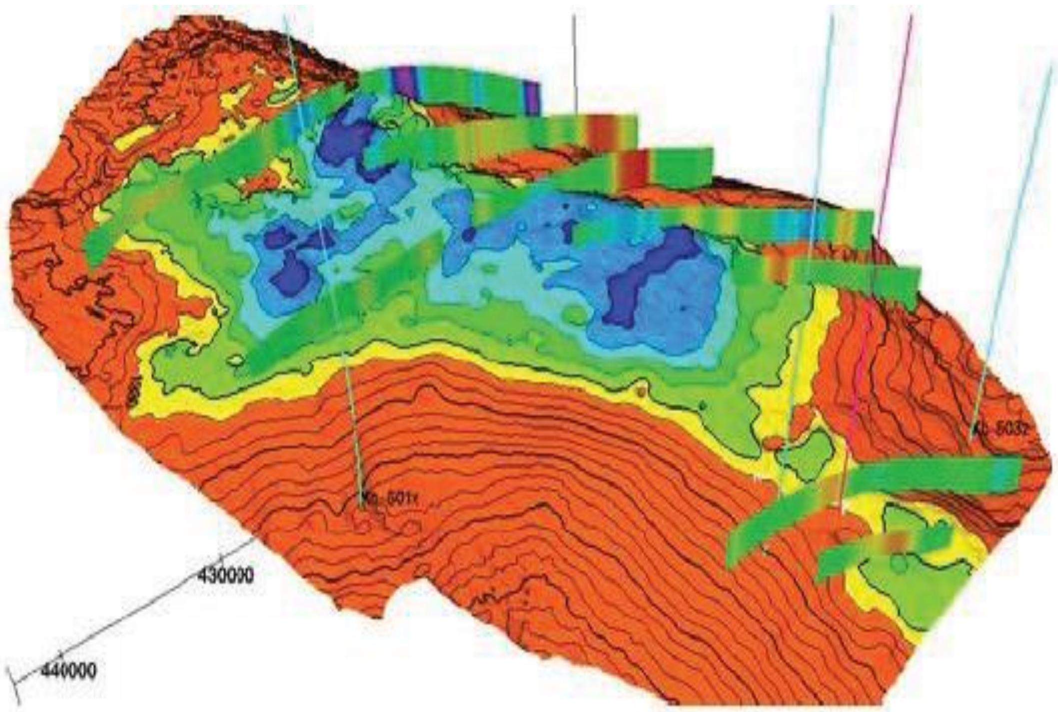
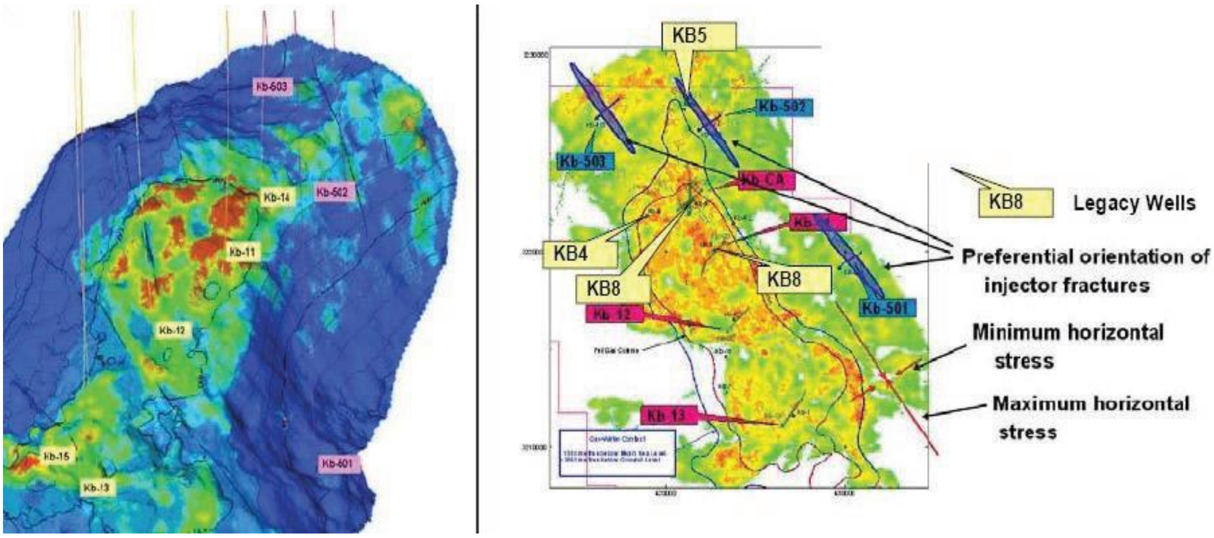
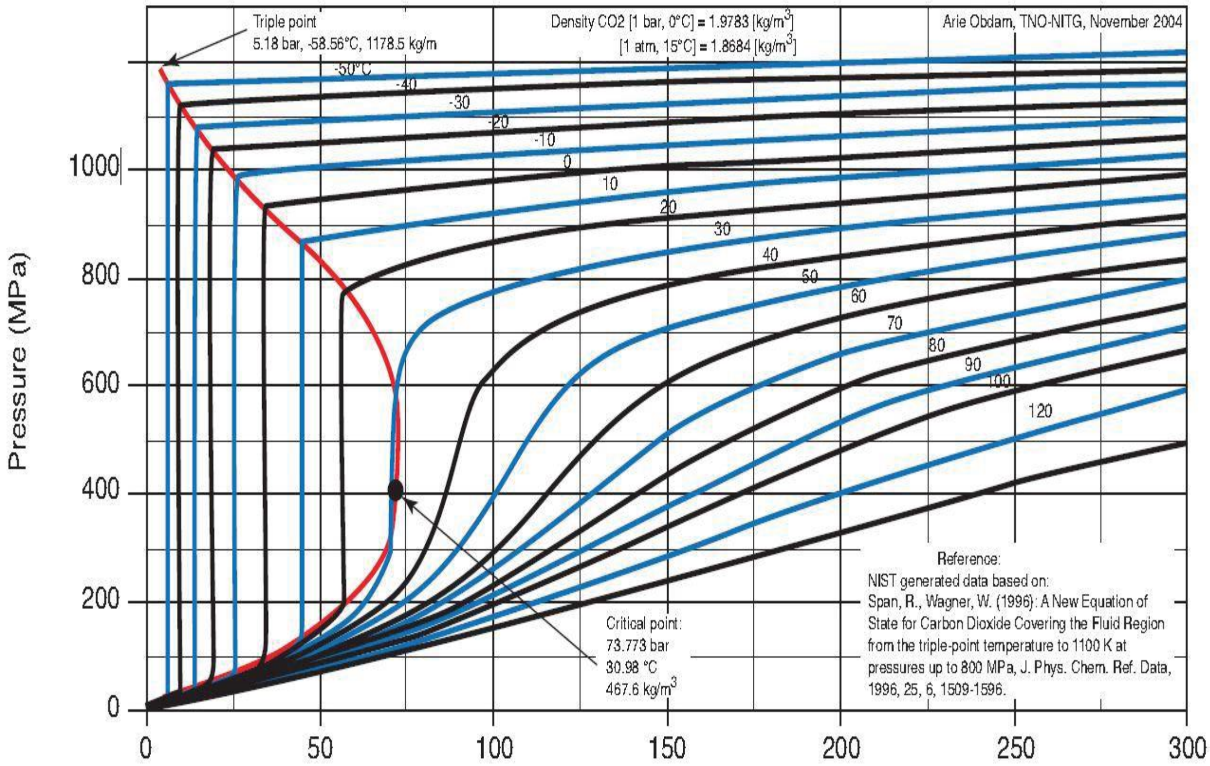
Annex:



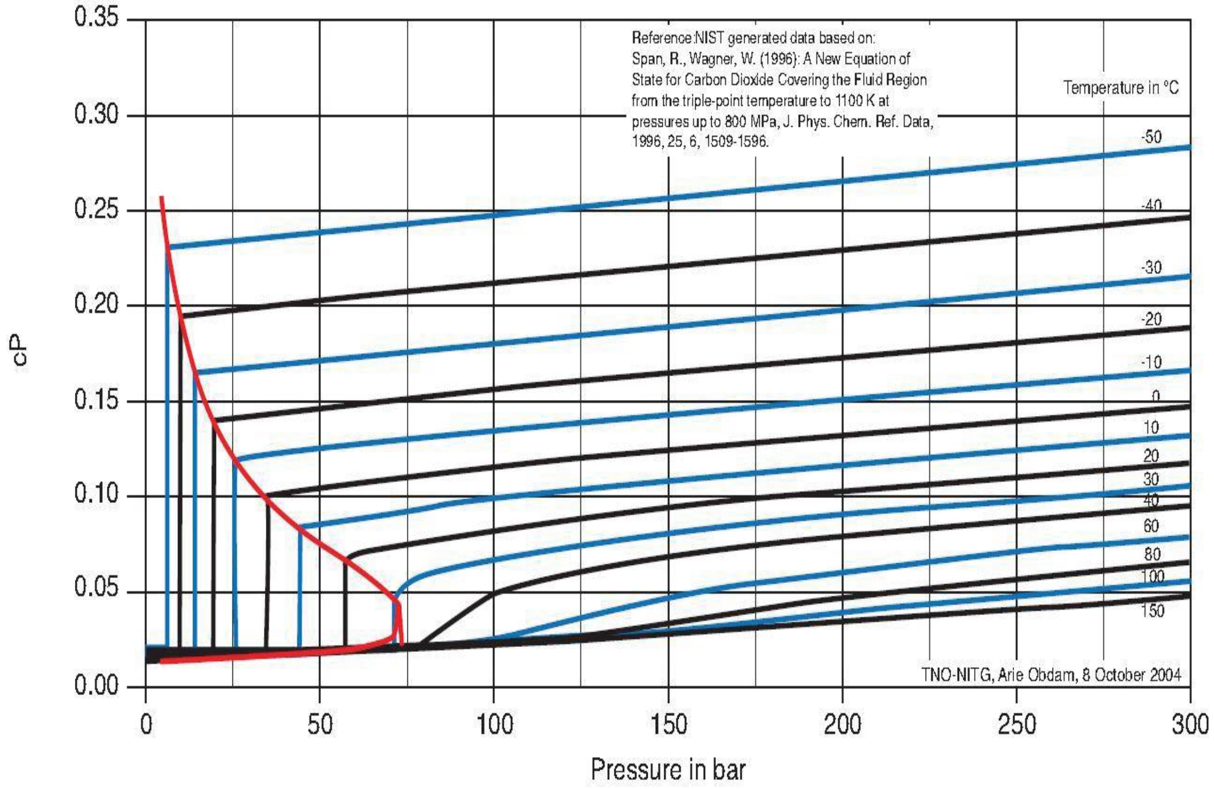
Annex 1: Map of the contour of the Top of the Carboniferous reservoir with the injection wells and producers, and faults (in green), represented on a porosity map.



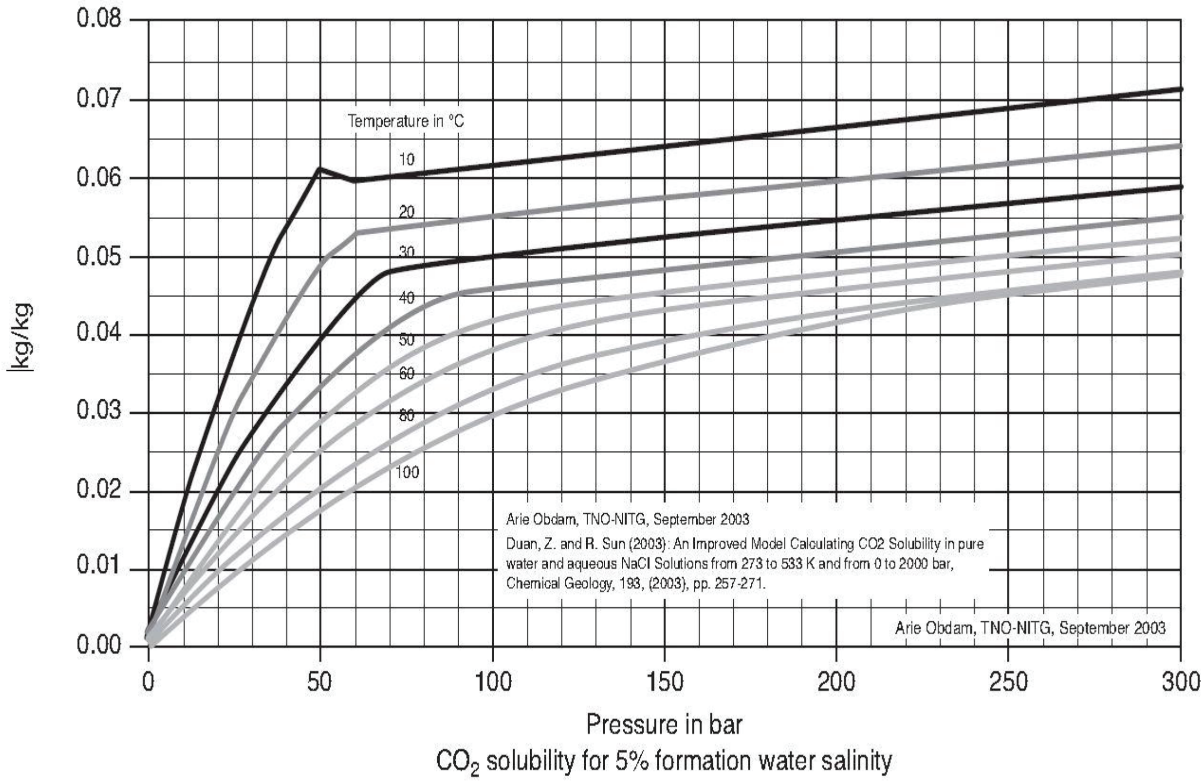
Annex 2 : Map of the Carboniferous Krechba, illustrating the orientation of natural fractures.



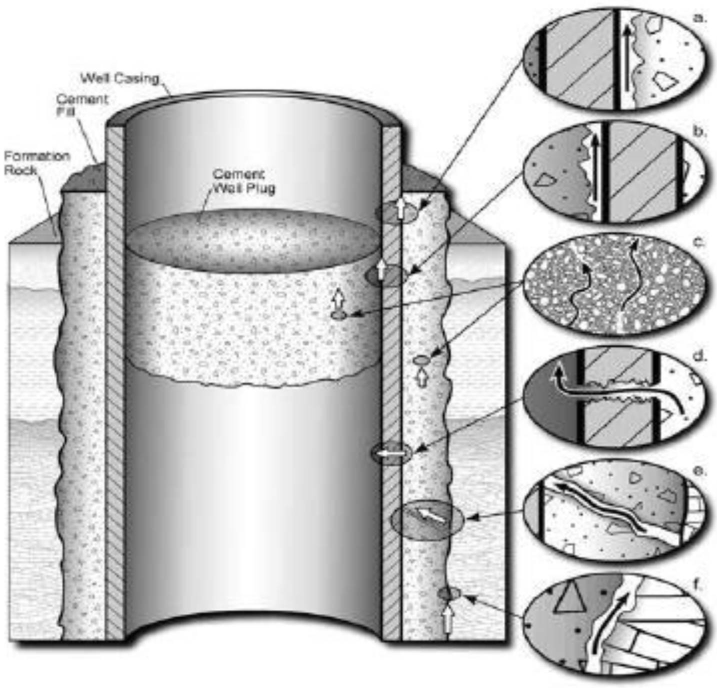
Annex 3: The density of CO_2 as a function of pressure and temperature.



Annex 4: Viscosity of CO_2 as a function of temperature and pressure.

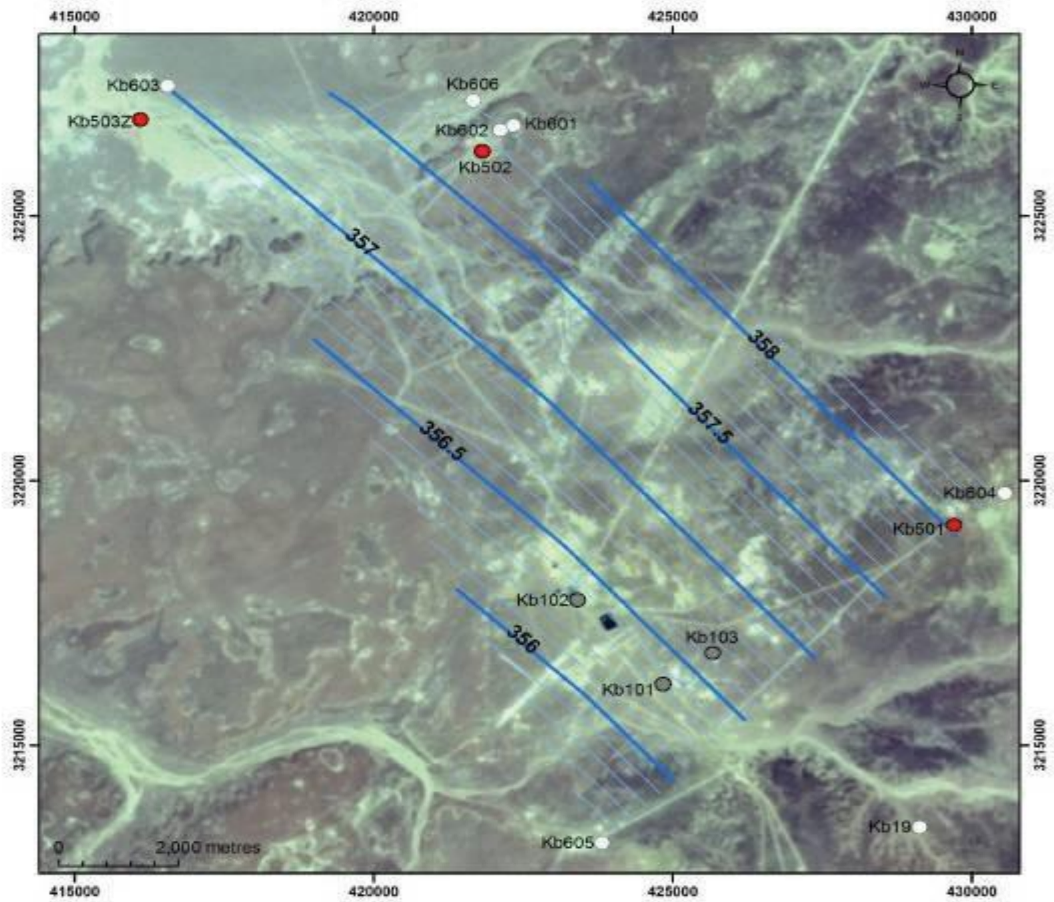


Annex 5: The solubility of CO_2 in salt water as a function of temperature and pressure.

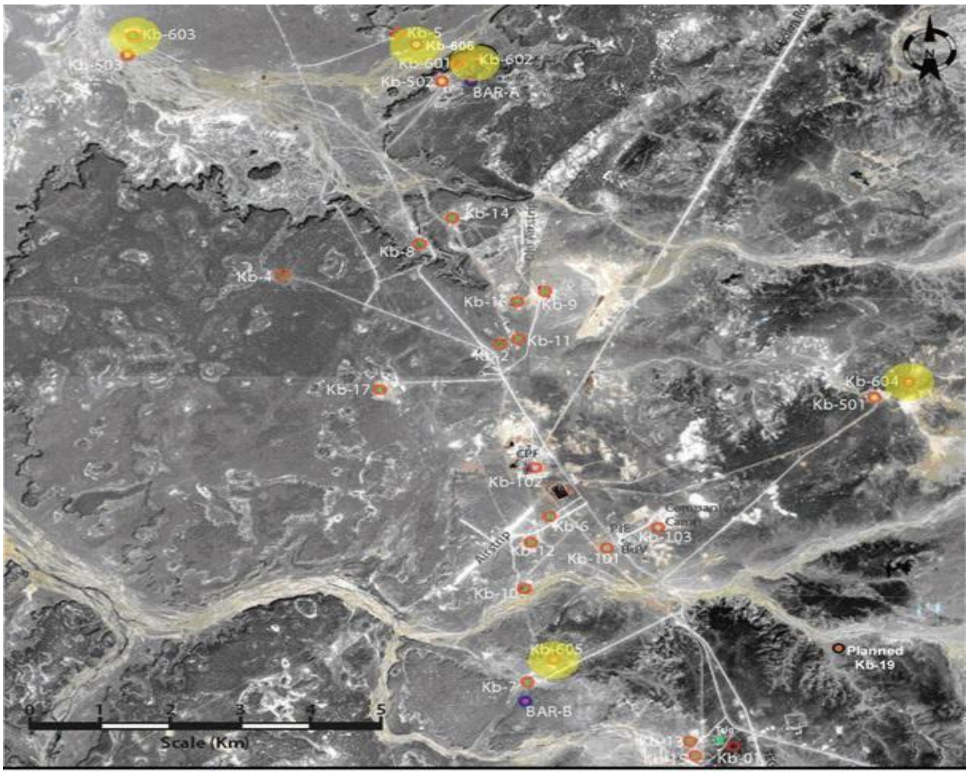


Annex 6: Presentation of leakage paths in an abandoned CO_2 injection well.

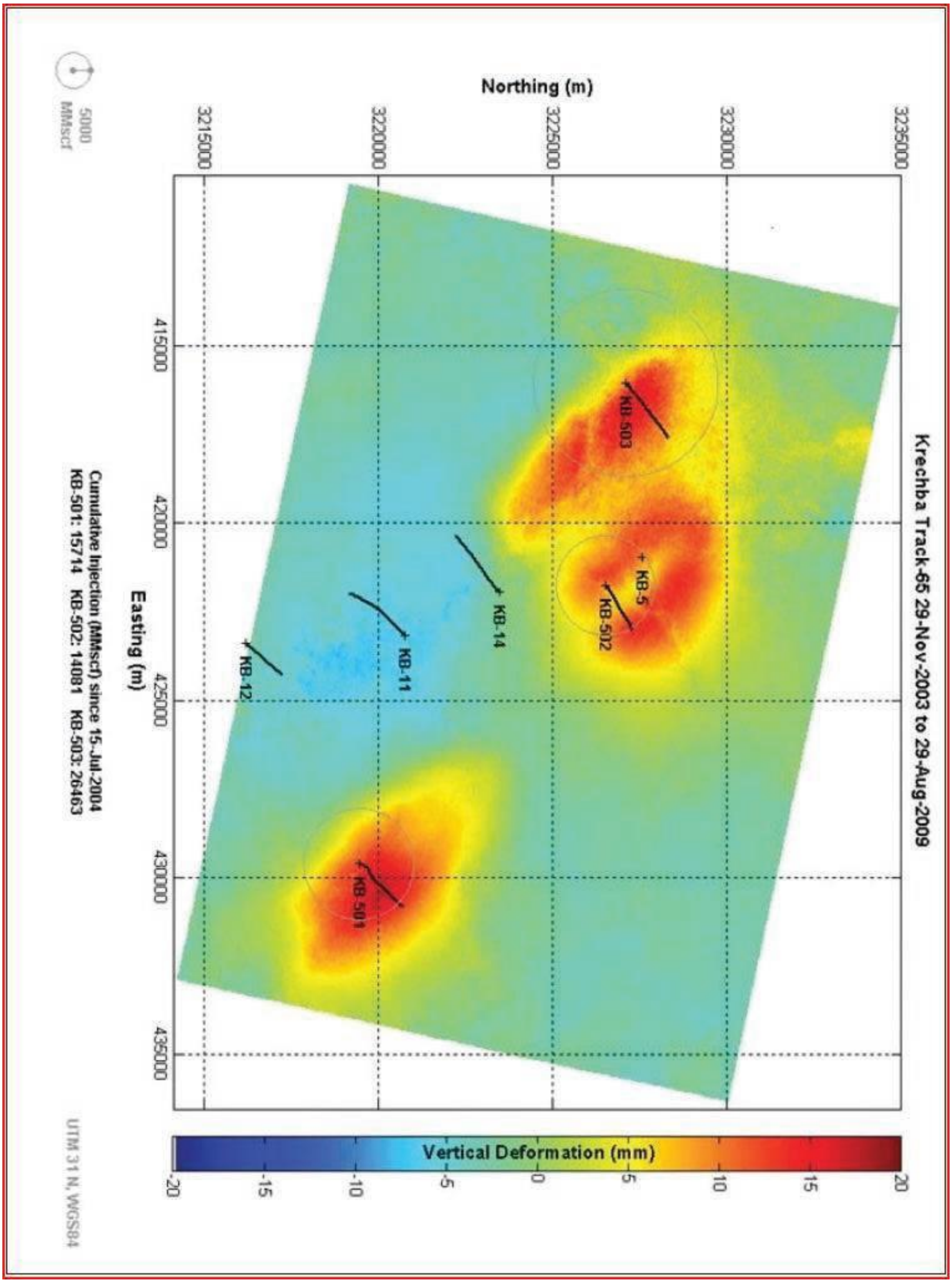
Legend: leak between the cement and the steel casing (a and b), through the cement (c and e), through the casing (d), between the cement and the rock (f)



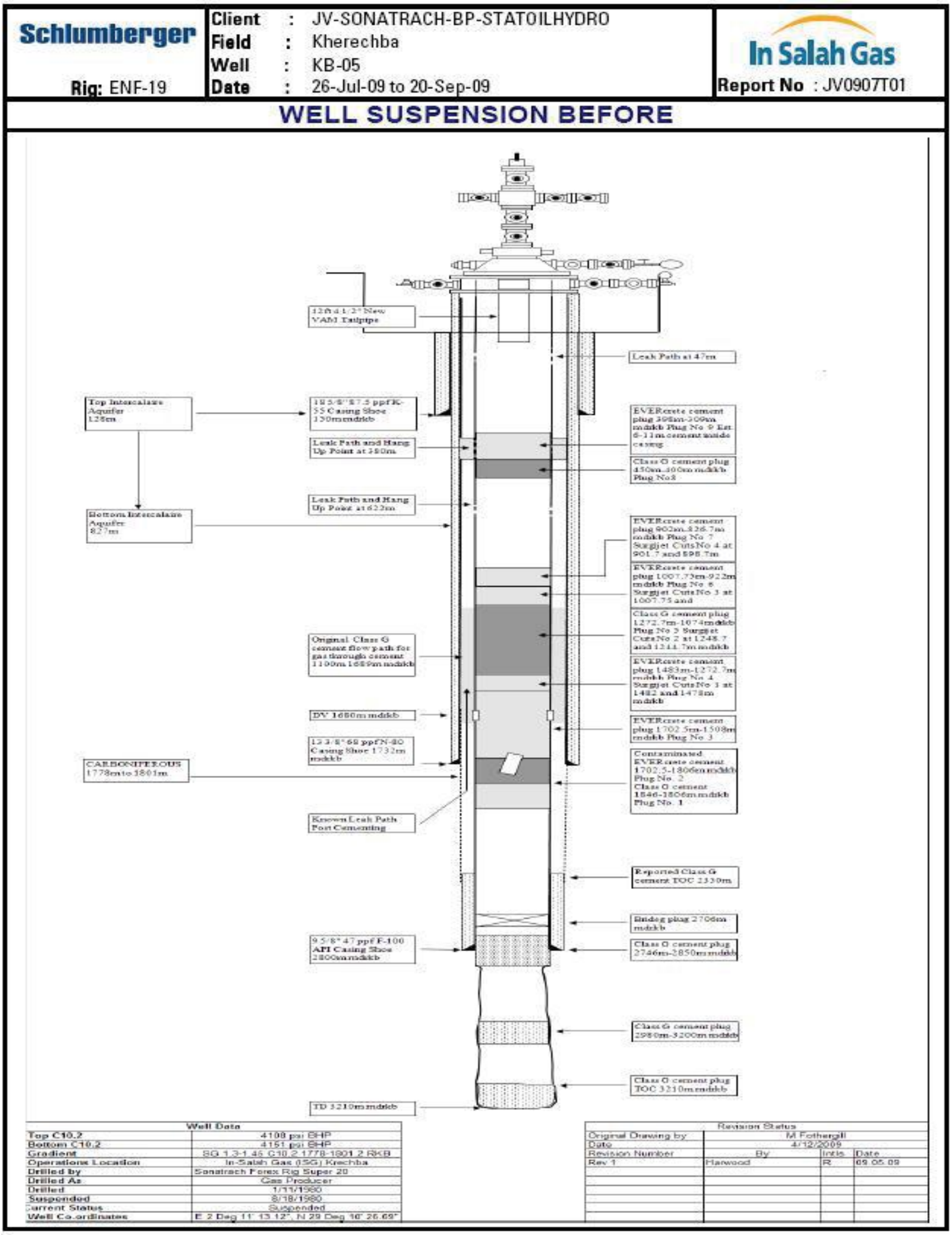
Annex 7: The Pan-Saharan aquifer is oriented towards the southwest and moves with a speed of 4 ~ $_{2}$0 m / year. [Image taken by satellite].



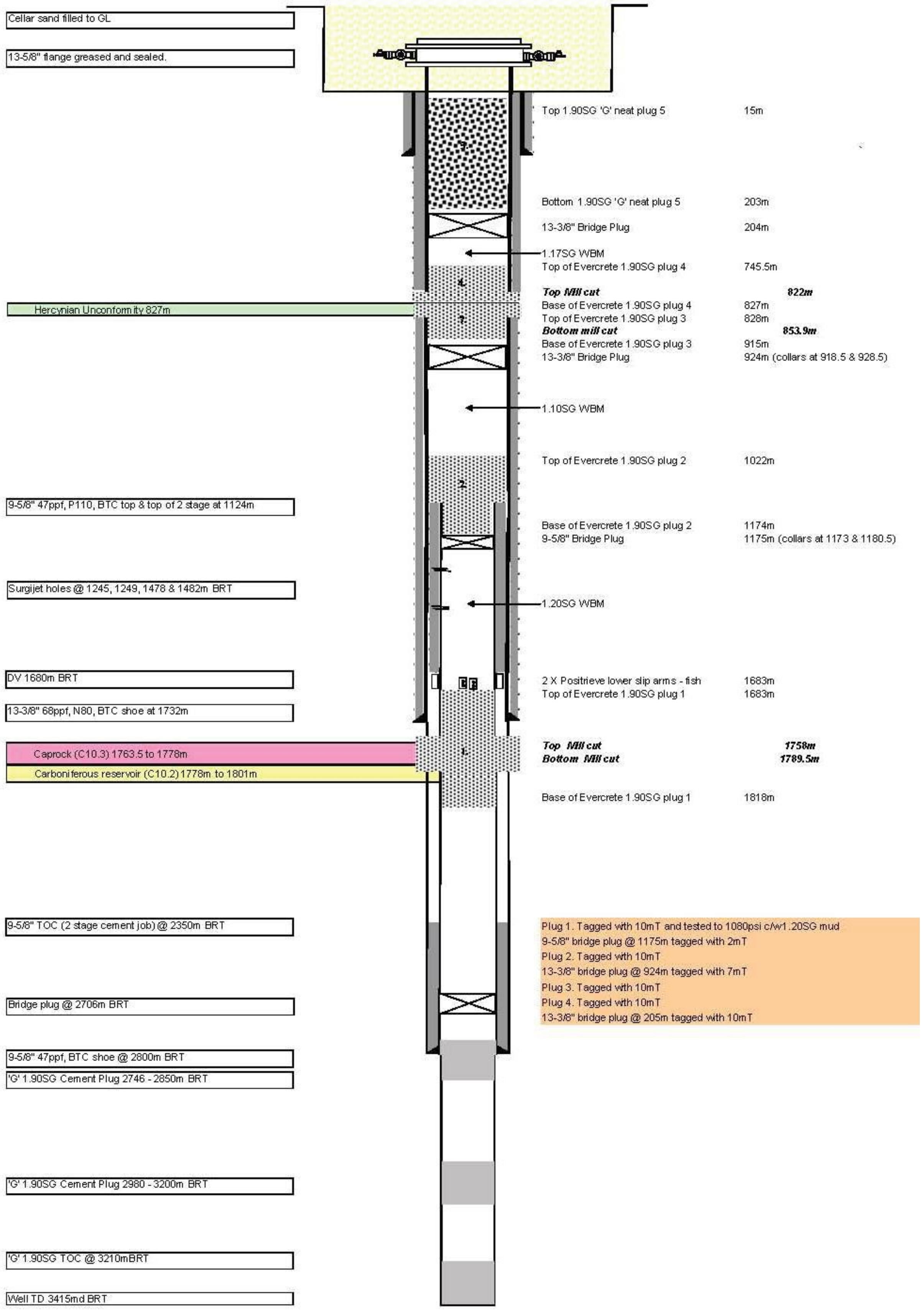
Annex 8: The five monitoring wells of the Pan-Saharan aquifer at Krechba [Satellite image].



Annex 9: Satellite image of surface deformation at Krechba after CO_2 injection. (Interpreted by MDA / Pinnacle



Annex 10: State of Kb-5 after phase II.



Annex 11: Completion of Kb-5 after final abandonment by the JV in 2009 (phase III).