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Criteria for Depleted Reservoirs to be Developed for CO_2 Storage

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CRITERIA FOR DEPLETED RESERVOIRS TO BE DEVELOPED FOR CO_2 STORAGE

(IEA/CON/20/268)

The long-term, secure storage of CO_2 depends on injection and retention within well characterised geological reservoirs, such as saline aquifers or depleted oil and gas fields. Depleted oil and gas reservoirs are often selected for first-generation CO_2 storage sites because they have been characterised from their discovery date, during the whole production phase and possibly during post-production observations. The potential CO_2 storage capacity in saline formations is well understood, and so the objective of this study is to specifically focus on a set of storage conditions that apply to depleted oil and gas fields. The study is split into three main sections: a review of case studies for CO_2 storage in depleted hydrocarbon fields; original research looking into reservoir pressure depletion, boundary conditions, the effect of residual hydrocarbons on injectivity and capacity; and the economics of infrastructure reuse for CO_2 storage sites. The third section discusses and integrates the lessons learned to facilitate evaluation of future depleted field storage opportunities.

Key Messages

- Depleted hydrocarbon fields are valuable and advantageous sites for the storage of CO_2.
- Site evaluation when considering depleted fields for storage should be project-specific and should consider the storage requirements and the operators' metrics for success and views of acceptable risk.
- Sub-hydrostatic reservoir pressure is a sign of closed or semi-closed reservoir boundaries and such reservoirs may offer greater storage security but also place limits on capacity.
- The presence of remaining hydrocarbon gas in place does not necessarily affect the CO_2 storage capacity of the depleted dry gas reservoirs, other than occupying pore space.
- The majority of a CO_2 plume in a depleted dry gas reservoir remains mobile, while capillary and dissolution trapping mechanisms play minor roles in trapping.
- Other than occupying pore space, the amount of remaining gas in place does not significantly affect the capillary and dissolution trapping efficiency of CO_2 plume in a depleted dry gas reservoir.
- Infrastructure reuse, based on a comparison of modelled examples, will not always result in lower costs for CCS projects.
- In all projects, outreach and public relations are crucial for reassurance.
- The best scenarios for CO_2 storage in depleted fields may be 'hybrid' situations, such as CO_2-EOR or injection into the water leg down-dip of a depleted reservoir.
- The report includes key guidance on Site Evaluation and Desirable Characteristics.

Background to the Study

The benefit of documenting and evaluating key criteria for depleted oil and gas reservoirs to be developed for CO_2 storage would be to provide a more refined estimation of the storage capacity of this type of site in the different areas of the world, particularly where there are high concentrations of large-scale industrial CO_2 emissions.

The potential CO_2 storage capacity in deep saline formations, and to a lesser extent storage associated with CO_2-EOR, is well understood and attempts by IEAGHG have been made to make regional and global capacity estimates[1] and CCS site selection and characterisation criteria[2]. The objective of this study is to specifically focus on a set of storage conditions that apply to depleted oil and gas fields (DO&GFs). These criteria do not necessarily apply to other potential storage formations. The significance of other facets that influence storage capacity, such as residual trapping, broaden the scope of this investigation. Whilst recognising the importance of this mechanism it would be better to investigate in a separate study given the potential scope and resource that might be required to produce a thorough piece of research.

DO&GFs are widespread and many are within reasonable proximity to large point sources of CO_2. There are some excellent examples of CO_2 storage in depleted reservoirs across the USA and Canada, and these examples are beneficial to other operators with less experience of utilising depleted reservoirs.

Scope of Work

The primary objective of this study is to identify and detail the key criteria for the development of depleted oil and gas reservoirs for CO_2 storage, based on in-depth case studies of depleted oil and gas reservoirs with the potential for CO_2 storage within specific regions. The work considered the advantages and disadvantages of using depleted fields for the storage of CO_2.

The work begins by detailing several case studies to frame the later discussions in the study and ground them in experience, cases chosen to illustrate the range of different storage in depleted fields. The study then presents original research on potentially under-appreciated sensitivities. These include: reservoir pressure depletion; boundary conditions; effects of residual hydrocarbons on injectivity and capacity; and the net value of existing infrastructure. The report then discusses these findings and uses these insights to generate guidance for prospective depleted field storage opportunities.

Findings of the Study

The study looked in detail at 10 case studies of storage in depleted fields, as listed in Table 1, overleaf. These studies were chosen on the basis of their operational experience. The case study section of the report describes in detail the parameters of the various fields, including information on usage, geological location and characterisation, field history, production history and previous research efforts at the sites.

The case studies describe a wide range of operational conditions associated with CO_2 storage in depleted fields. Reservoir parameters were highly variable, for example injection into the hydrocarbon reservoir or down-dip into the water leg which creates a wide range of potential hydrocarbon saturations at the point of injection, or reservoir pressures at the start of injection ranging from highly depleted to hydrostatic. Another factor drawn out by these examples was the difference in the current state of practice between CO_2-EOR and pure storage and it was recognised that casting storage projects as CO_2-EOR often offers an easier path to permitting and public acceptance.

[1] CO_2 Storage in Depleted Oil Fields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery, IEAGHG 2009-12
[2] CCS Site Selection and Characterisation Criteria, IEAGHG 2009-10

Name			Location			Field Characteristics				CCS	
Field	CCS Project	Operator	Country	Basin	onshore/ offshore	Depth (m)	Reservoir type	HC phase	HC production status	Carbon storage scheme	CO_2 stored to date
Rousse	Lacq Pilot Project	Total	France	Aquitane	onshore	4200	carbonate	gas	depleted	post-production	51kt
Naylor	CO2CRC Otway Project	CO2CRC Pilot Project Ltd	Australia	Otway	onshore	2050	clastic	gas	depleted	post-production	65kt
Weyburn-Midale	Weyburn-Midale CO2 Project	PCOR Partnership	Canada	WCSB	onshore	1400	Carbonate	oil	active EOR	EOR	
SACROC (Kelly-Snyder Field)	Southwest Partenrship Ph II	Kinder Morgan	United States	Permian	onshore	6700	Carbonate	oil	active EOR	EOR	~80Mt
Cranfield	SE Reg. Parternship "Early" test	Denbury	United States	Gulf of Mexico	onshore	3100	clastic	oil	active	syn-production	5.37Mt in test; exculding EOR)
K12-B	K12-B	GPN	Netherlands	Southern Permian	offshore	3800	clastic	gas	depelted	syn-production	100kt
Krechba	In Salah	In Salah Gas JV	Algeria	Ahnet	onshore	1800	clastic	gas	active	syn-production	3.8Mt
Hastings	Hastings	Denbury	United States	Gulf Coast	onshore		clastic	oil	active EOR	EOR	~7Mt
Wasson	Wasson Denver Unit	OXY	United States	Permian	onshore	4900	carbonate	oil	active EOR	EOR	
Altmark	Project CLEAN	GDF SUEZ E&P	Germany	Southern Permian	onshore	3400	clastic	gas	depleted	post-production	N/A

Table 1. **Summary of case studies presented in the report** *(IEAGHG, Report number 2022-01, page 12)*

These case studies offer insights into the application of different techniques:

- 4D seismic has limited value in tracking plume migration because the contrast between hydrocarbons and CO_2 is small, but the technique is excellent for spotting leaks into saline aquifers.
- Surface gas and water monitoring can be complicated by high seasonal and diurnal variations in CO_2 flux.
- Pressure monitoring is key to maintaining and updating reservoir models and useful for verifying that pressure is maintained within safe injection limits, but pressure monitoring within the reservoir is unlikely to spot leaks. The Cranfield site showed that above-zone pressure monitoring was the most effective leak detection technique.
- Monitoring microseismicity is cost-effective and essential for the attribution of seismicity. It can be useful for tracing the plume and may be critical for verifying that injection stays within fracture pressure limits.
- InSAR is cost effective and may be useful in the right circumstances but needs careful processing and geomechanical modelling to make sense of the observations.
- Monitoring wells offer unique insights and are excellent for research but potentially expensive and not universally needed.
- Tracers are important for tracking plume movement and updating reservoir models where there is naturally occurring CO_2 and production / monitoring wells available.
- Individual techniques are useful but most powerful when combined to complement each other.

Effect of residual fluids on storage efficiency

Following previous work on numerical simulation of CO_2 injection in depleted hydrocarbon fields, this study's first modelling section evaluated the effect of residual gas on the storage capacity and trapping efficiency of CO_2 stored in a depleted gas reservoir. A 3D geological model that is representative of a hydrocarbon sand gas reservoir in a field located in offshore Texas state waters (analogous to a depleted reservoir applicable to this study) was applied. A rough estimation of the storage capacity of the reservoir was made using a volumetric method. Knowledge of the original and remaining gas in place (GIP), and application of an efficiency factor from previous studies, was applied. The model investigated a 10-year injection period with 100 years of post-injection modelling to evaluate the long-term behaviour of the CO_2. It should be noted that this is not a recommended period for post-injection monitoring. It was selected purely arbitrarily.

The different scenarios studied had varying amounts of GIP and the trend of pressure rise in the reservoir during injection is identical for all cases, as shown in Figure 1, below. Trapping mechanisms were also investigated in terms of mobile, residual and dissolved CO_2.

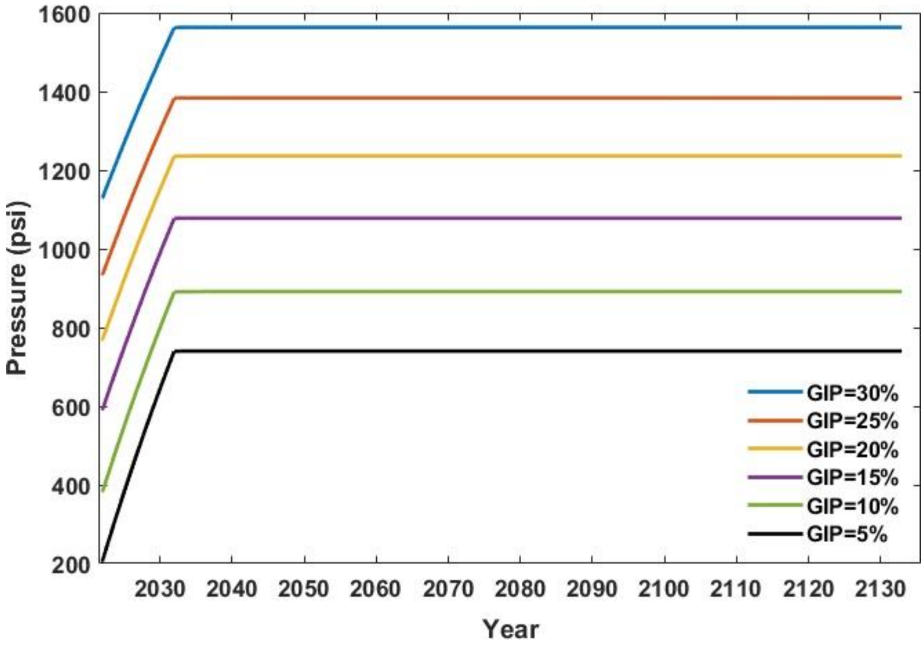

Figure 1. **Time evolution of reservoir pressure during injection and post-injection periods in the depleted reservoirs containing various levels of remaining GIP** *(IEAGHG, Report number 2022-01, page 65)*

The results show that the presence of remaining gas in a depleted reservoir does not necessarily affect the storage capacity and the maximum pressure build-up was far below the original pressure corresponding to the pre-production phase. The CO_2 plume tends to migrate upward during injection and then starts to recede and accumulate at the bottom of the reservoir when injection ceases, while the remaining gas (methane) fills the regions below the reservoir top. Therefore, a depleted reservoir with a higher amount of remaining GIP may provide better storage integrity because the formation of a thicker gas cushion decreases the risk of CO_2 migrating upwards toward the top sealing layer of the reservoir after injection. Results show that the majority of the CO_2 plume remains mobile and the amount of remaining GIP does not significantly affect the residual and dissolution trapping efficiency of the CO_2. Thus, a solution to better engineer the residual and dissolution trapping efficiency in depleted gas reservoirs could be to employ water-alternative-CO_2 injection. This practice would improve capillary and dissolution trapping. In such a situation, water injection should be optimised to ensure it does not limit storage capacity.

Impact of boundary conditions and pressure depletion

Pressure is an important factor in determining storage capacity. The study uses EASiTool modelling (a software package developed at the Gulf Coast Carbon Center specifically for estimating injection capacity and pressure build-up) to look at the high-level capacity implications of pressure depletion. It was also created using typical Gulf of Mexico coastal reservoir parameters. CMG (a commercially available reservoir modelling software package) modelling was also used to further investigate the effect of pressure depletion on the storage capacity.

Four scenarios were looked at:

- Case A - a base / reference case representing a wet reservoir with no connection to a larger aquifer.
- Case B - a pressure-depleted case representing a post-production field with 50% pressure depletion.
- Case C - a large aquifer case representing a post-production field with good aquifer connection and therefore no pressure depletion.
- Case D - a comparison case, a hybrid model with hydrostatic initial pressure and open boundaries but limited injection.

Maximising capacity and (or) limiting pressure build-up for a given injection volume favours those fields with open boundaries. This condition allows the displacement of pore fluids and dispersion of injection-related pressure build-up beyond the field boundaries. As a result CO_2 storage capacity is many times greater than a similar field with closed boundaries. However, pressure propagation could create a larger area of review to consider and could impact other storage projects nearby. The project operator needs to decide whether such trade-offs make business sense.

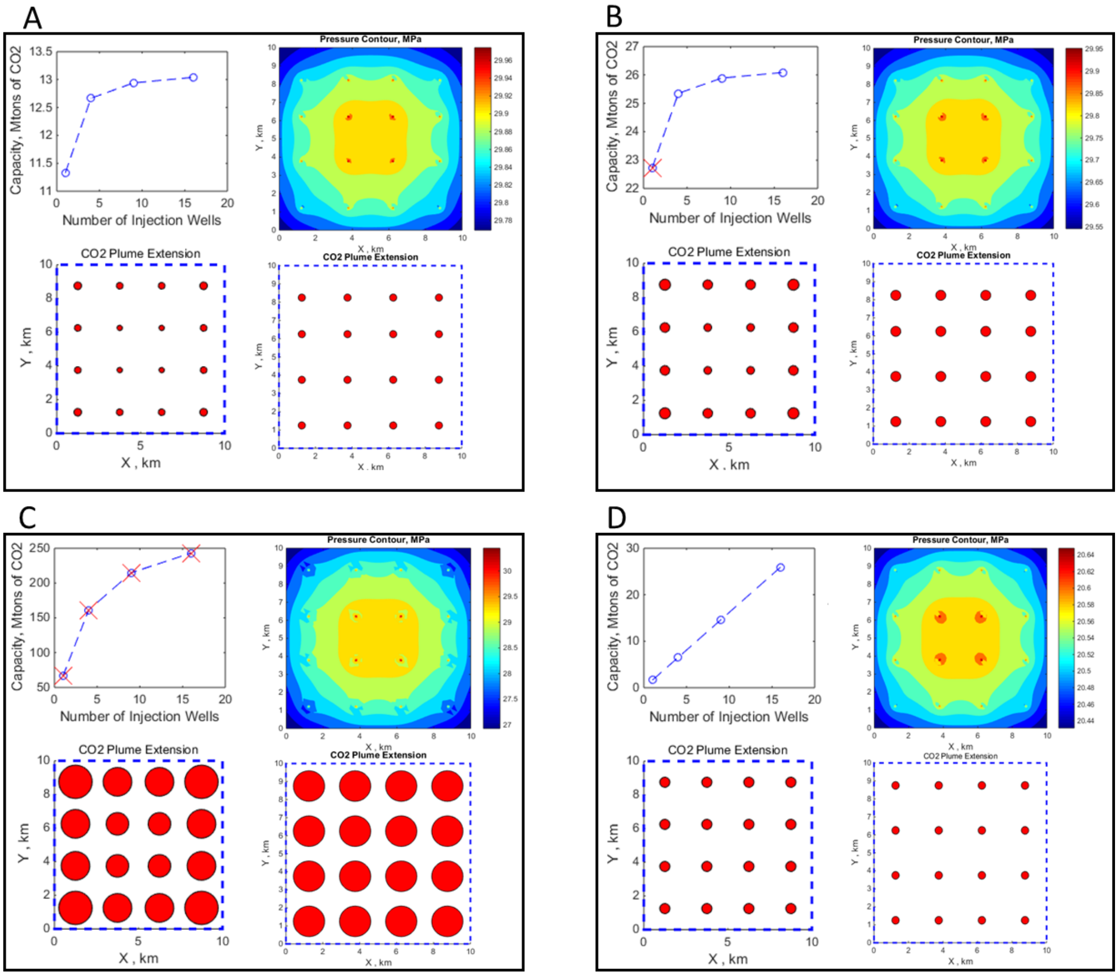

Figure 2. **Results of the EasiTool modelling exercise. A – Reference case, B – pressure-depleted case, C – open boundary case, D – limited injection case.** *(IEAGHG, Report number 2022-01, page 73)*

Closed reservoir boundary conditions create potential security for storage operations as they can operate in a proven pressure space by limiting the post-injection reservoir pressure to its proven pre-production value. This approach ensures that CO_2 / injection-related pressure will remain laterally confined. However, closed boundaries limit the availability to dissipate pressure build-up and therefore limit storage capacity. Models show that a hydrostatically pressured field with open boundaries may offer ten times the capacity of a similar field with closed boundaries, even if reservoir pressure is initially 50% lower. Figure 2, above, shows the EasiTool model results for all four scenarios, noting that the top left panel in each box shows storage capacity as a function of the number of injectors where maximum pressure cannot exceed 30 MPa. Red Xs show wells that denote injection rates greater than 2,000 tonnes /day, which is not impossible, but a flag to check assumptions. The bottom left panel in each box shows a map view of the resulting CO_2 plume spread. The top right panel in each box shows the maximum pressures in map view when every well injects at the same rate (rate chosen to give the same total storage over the 20-year model run). The bottom right panel in each box shows the map view plume spread with constant injection rate. More detail can be found in the main body of the report.

In real life, fields often have semi-closed boundaries where there may be a limited time available for storage operations to take advantage of post-production pressure draw down. Injection-related pressure build-up may be slower and will dissipate over time. Injection into highly pressure-depleted fields carries operational challenges and may require special completions to avoid adverse events such as formation of water ice or precipitation of salts in the near-wellbore reservoir.

Economics of infrastructure reuse

The report also looks at the economics of infrastructure reuse by developing a framework that assesses the costs of a project that could store 1 million metric tonnes of CO_2 per year over a 25-year active injection period in a DO&GF (total storage of 25 million tonnes). A monitoring period of 20 years post-injection, with a total project life of 45 years has been assumed. The work looks at four different scenarios: using new onshore infrastructure; reuse of existing onshore infrastructure; new offshore infrastructure; and reuse of existing offshore infrastructure. The costs for each case were estimated and included a sensitivity analysis to develop uncertainty ranges for capital costs (CAPEX) and overall performances. The focus was placed on CAPEX of major components as it was assumed operating costs (OPEX) would be similar for both new and reconditioned existing infrastructure.

For the new onshore infrastructure scenario, the essential parts covered drilling pad and road work, well drilling and completion. The pipeline, as well as other auxiliary infrastructure needed to move and manage CO_2 to the sequestration site, were also included. It must be remembered that the ranges of costs for these categories will of course be site-specific, dependant on location, access, well condition and characteristics of the receiving reservoir. For a typical project with the ability to store 1 Mtpa of CO_2, including 50 km of pipeline infrastructure, the upfront CAPEX costs of using new onshore infrastructure would be about US $40M, with a range of between US $28.1M and US $51.9M.

With reuse of existing onshore infrastructure, considerations were made for drilling pad and road work, wellfield assessment, well drilling and equipment, injection and monitoring wells, existing well remediation and pipeline costs. The pipeline is a major expense here (using the same project as above, a 1 Mtpa of CO_2 storage effort), constituting roughly 75% of the potential upfront costs. If a pipeline was available already at the depleted field, and could handle the pressure with some additional pressure booster stations, or if the existing pipeline could transmit the CO_2 at lower pressures (i.e. the pipeline is of sufficient diameter for flowrates desired for CO_2 in a gaseous form), the costs would be between US $9.3M and $16.8M. However, if the pipeline needed to be replaced, this would increase the overall project CAPEX to around US $39.5M.

For new offshore infrastructure major costs will include, the platform, drilling and completing and the pipeline. Each of these components being generally more expensive than onshore. The total CAPEX for new offshore infrastructure were shown to be roughly ten times higher than those of onshore projects, costing around US $400M (CAPEX), with sensitivities ranging from US $273.5M–$523.2M.

Significant cost savings could be realised through the reuse of existing offshore infrastructure but it cannot be assumed that all existing infrastructure has the potential to be equally useful. Pipelines are likely to be the most useful component to reuse and other aspects (e.g. platforms and wells) have limited reuses. There are more unknowns with the reuse of offshore oil and gas infrastructure as they are significantly more tailored to a site than their more homogenous onshore counterparts. The work estimated that the reuse of major pieces of offshore infrastructure for a CO_2 storage project may cost between US $93.8M–$413.3M upfront.

The analysis cautions against the assumption that the reuse of existing infrastructure will always, or even often, provide significant cost savings; even if large segments of existing infrastructure are useful. There are likely to be uncertainties as to whether it will be useful for a particular project. Existing infrastructure has the potential to be useful and reduce costs, every project is highly site-specific and factors such as pipeline pressures and the number of legacy wells that might need remediation must be considered.

Conclusions

Depleted hydrocarbon fields are valuable sites for the storage of CO_2 but this work shows that there is no single set of evaluation criteria that works for all projects. Evaluation should be a project-specific process that considers the storage requirements and the operators' metrics for success and views of acceptable risk, and this means that different site parameters will assume different priorities. Regardless of differing success metrics, evaluation begins with five key criteria:

1. **Injectivity**
   Injectivity is a primary control on the injection rate for a reservoir and the rate of CO_2 storage needed places constraints on the injectivity required, proportional to the reservoir thickness and permeability.
2. **Storage capacity**
   Capacity is a function of the accessible pore space, the difference between initial and final reservoir pressure, final in-reservoir CO_2 density and temperature/salinity of formation water. Depleted fields offer fluid replacement – a large fraction of the pore space once occupied by produced fluids can be re-occupied by injected fluids. More additional capacity can be access in fields with open and closed boundaries, with more potentially available in fields with open lateral boundaries. Although a potential benefit, this increased capacity provides a greater containment risk and larger area of review to consider.
3. **Containment security**
   Long-term containment is imperative to project success. Depleted fields have seals that are proven to be capable of retaining hydrocarbons over geological timescales. Factors must be considered that will compromise and / or enhance the security, including change in fluid type, legacy wells, increased pressure and layered/multiple seals.
4. **Reusable infrastructure**
   It might seem obvious that existing infrastructure would reduce project development costs. However, it is important to note that not all infrastructure will be reusable and the cost of remediating wells, and modifying pipelines or platforms, could offset costs saved elsewhere. Pipelines and platforms are the largest costs and this study suggests focusing screening criteria on whether these elements will be reusable. For pipelines the key factors to consider are capacity, pressure rating and remaining service life. The key consideration for platforms is their remaining service life which is extremely dependent on specific project requirements.

With projects where there is existing infrastructure, there will be data in well logs and production history. These data will be of huge value when characterising the field for CO_2 storage, planning monitoring programmes, and for creating / history-matching reservoir models. Consequently, it is recommended that any screening should favour fields without large data gaps.

5. **Public acceptance & regulatory approval**
   Public and regulatory acceptance is incredibly site-specific. The most valuable contribution to advancing the deployment of CCS and CO_2 storage projects will be early, transparent and open communication with regulators and community leaders.

The study suggests specific screening parameters for depleted fields. It is recognised that desirable factors for CO_2 storage are:

- A depth of over approximately 800m-1,000m below a freshwater aquifer, noting that additional depth offers potential additional security.
- Capacity of 25-50% more than the project requirements, noting that excess capacity adds a margin of safety and fields with open boundaries may offer extra capacity.
- Injectivity of 25-50% over the project requirements, noting that injection rate can be increased by employing more injection wells.
- Number of legacy wells should be less than 5 and no more than 20 with a desirable age of younger than 1980, noting that there is no hard rule for this criterion. The more legacy wells, the greater the cost for review and possible remediation.
- It is desirable to have infrastructure that is in active service and nearing the end of its field life (not yet decommissioned).
- Pipeline pressure should be less than 15 MPa, noting that lower pressure ratings can be used with injection-site compression.
- It is desirable to have complete, accessible, high-quality data for production history, 3D seismic and well logs.
- In terms of regulatory readiness, it is desirable that the area has a complete legal framework in place or local regulators who are willing to bridge gaps.
- A local community who are accepting, or enthusiastic, about CCS or at least who are not actively opposed to it.

The study recognises that the best situations may be hybrid scenarios, such as CO_2-EOR and injection into the water leg down-dip of a depleted reservoir. CO_2-EOR has many benefits including a dual income stream, previous data record, mature permitting and regulation and the ability to balance injection and production. The practice maintains reservoir pressure and the ability to control the migration of the CO_2 plume. There are still requirements needed to be met for EOR projects but those that pass these requirements create additional attractive storage options. Injecting down-dip of the hydrocarbon-water contact in a depleted field offers the same benefits as injection straight into a field. This practice has other advantages such as potential increased capacity and injectivity, stand-off from legacy wells and a proven trap at the end of the migration path. An injector location down-dip offers a large range of potential sites.

The potential risks to success of a storage project were ascertained using particularly the case studies in the report, and include:

- Mismatched reservoir injectivity and CO_2 production rate.
- Mismatched reservoir capacity and injection rate.
- Public acceptance.
- Induced seismicity.

These potential risk factors do not necessarily block a project but should be considered in the planning stage and could be easily mitigated by design.

The study shows that the science of storage in depleted hydrocarbon fields is confirmed and can be successful. Pressure-depleted fields offer greater latitude for injection-related pressure increase but are depleted in part due to closed / semi-closed boundaries. They can offer advantages such as sufficient capacity and high security. The fraction of residual methane has a small effect on storage capacity and injectivity. Higher residual methane can negatively affect residual and solubility trapping efficiency, but hydrocarbon gas mixing with the injected CO_2 increases plume mobility which leads to enhancement in the injectivity and pressure management in the reservoir. Existing and inherited infrastructure should be considered carefully, as it is not always viable for reuse and pipeline costs are the biggest driver for project cost in terms of new infrastructure. The key factors to consider for the use of depleted hydrocarbon fields for CO_2 storage are storage capacity, reservoir injectivity containment security, potential for infrastructure reuse and the risks to regulatory approval and public acceptance.

Expert Review

Six expert reviewers were invited to provide feedback on the draft report and five responded with varying levels of comments, many significant. There was agreement that the case study effort provided valuable insights and lessons learned from CO_2 storage in depleted fields, although some important projects have been omitted. It was recognised that this study has great value for documenting key criteria for depleted hydrocarbon fields and represents current industry understanding.

Although there was broad appreciation of much of the work done, particularly the case study section, there were a significant number of comments particularly on the modelling section of the report. More clarity was required in the model set up and description. Reviewers also felt the effect on residual fluids could be better explained. The results attributed to the mixing of residual methane and injected CO_2 were called into question. CO_2 injection can significantly change the system pressure and under these conditions the effect of residual methane was possibly overstated.

Some reviewers suggested that there should be more analysis on fields at low or very low pressure as they could offer significant advantages and some significant challenges. These conditions could provide deeper insight in the parameters that define field attractiveness. Another observer thought that there was too much focus on the modelling to the exclusion of some the key features of depleted fields. The content needed to connect the insights and approaches from existing work to strengthen the modelling section.

As a result of the significant external commentary the contractors responded judiciously to all comments received and diligently amended the draft report, which involved a significant reworking of the second section of the work and new modelling exercises. More detail and clarity was provided throughout with attention paid to connecting the insights and lessons learned to help with evaluation of potential future storage sites.

Recommendations

This study offers a valuable record of the key criteria that operators should consider when looking into depleted hydrocarbon fields for potential CO_2 storage. The outcomes of this work lead IEAGHG to make several recommendations for future work, including:

- More case studies of depleted oil and gas fields (DO&GFs) should be investigated, particularly projects that have reached the permitting phase for CO_2 storage.

- Further work should investigate the monitoring of CO_2 in a depleted field.
- It would be useful to consider more information on the cost-benefit analysis of storage in depleted hydrocarbon fields.
- Pipelines and platforms are the largest costs and this study suggests focusing potential further guidance in assessing these two cost elements in the case of reuse.
- Details could be taken from this work and used to create a comprehensive step-by-step guidance document for operators when selecting and evaluating a potential depleted field for CO_2 storage.

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Contents

List of Acronyms and Abbreviations

Acronym	Meaning
3D	Three-Dimensional
ANN	Artificial Neural Network
AoR	Area of Review
API	American Petroleum Institute
AZMI	Above Zone Monitoring Interval
Bcf	Billion cubic feet
Bcm	Billion cubic meters
Bscf	Billion standard cubic feet
BEG	Bureau of Economic Geology, University of Texas
BHP	Bottom-Hole Pressure
C	Celsius
CAPEX	Capital Expenditure
CBL	Cement Bond Log
CCS	Carbon Capture and Storage
CH_4	Methane
CMG	A commercially available reservoir modeling software package
CO_2	Carbon dioxide
D	Darcy
DOE	US Department of Energy
EGR	Enhanced Gas Recovery
EIA	US Energy Information Administration
EMIT	Electromagnetic Imaging Tool
EOR	Enhanced Oil Recovery
EPA	US Environmental Protection Agency

F	Fahrenheit
FVF	Formation Volume Factor
GHG	Greenhouse Gas
GIIP	Gas Initially In Place
GIP	Gas In Place
Gt	Gigaton
H_2S	Hydrogen Sulfide
HC	Hydrocarbon
IWR	Injection:Withdrawal Ratio
InSAR	Interferometric Synthetic Aperture Radar
k	permeability
kg	kilogram
kPa	Kilopascal
kt	Kiloton
LLC	Limited Liability Company
LP	Limited Partnership
M	Million
m	meter
mD	Millidarcy
MIT	Mechanical Integrity Test
mm	millimeter
mmbbl	million barrels
MMP	Minimum Miscibility Pressure
Mscf	Million standard cubic feet
mmscf	million standard cubic feet
MPa	Megapascal
MRV	Monitoring, Reporting and Verification

Mt	Megaton
Mtpa	Megaton Per Annum (million tons / year)
nD	Nanodarcy
NETL	National Energy Technology Laboratory
NIST	National Institute of Standards and Technology
NPC	National Petroleum Council
O&G	Oil and Gas
OPEX	Operating Expenditure
P&A	Plug and Abandon
Pa	Pascal
ppmv	parts per million by volume
Psi	pounds per square inch
RCSP	Regional Carbon Sequestration Partnership
RF	Recovery Factor
ROZ	Residual Oil Zone
RRC	Railroad Commission
SACROC	Scurry Area Canyon Reef Operators Committee
SECARB	Southeast Regional Carbon Storage Partnership
STP	Standard Temperature and Pressure
Tcf	Trillion cubic feet
TVDSS	True Vertical Depth Sub-Sea
TX	Texas
UIC	Underground Injection Control
UK	United Kingdom
US	United States
USA	United States of America
USD	US Dollars

USDA	US Department of Agriculture
VSP	Vertical Seismic Profile
WAG	Water Alternating Gas
WOS	Wellhead on a Stick

Executive Summary

In this review we consider advantages and disadvantages of using depleted fields in comparison to deep saline reservoirs as carbon dioxide (CO_2) storage sites. The study consists of three parts. The first looks at ten case studies with operational experience and the insights they offer. The second presents original research on three factors that may impact evaluation of depleted field storage opportunities: 1) the impact of reservoir pressure depletion on storage capacity prediction; 2) the effect of residual hydrocarbons on capacity and injectivity; and 3) the net economic benefit of inherited hydrocarbon infrastructure, including elements that are reusable and those that are not. The third section is a discussion of criteria for evaluating depleted fields for CO_2 storage.

Key findings:

- Depleted hydrocarbon fields offer many attractive advantages for CO_2 storage, including extensive reservoir data, proven geologic containment and potentially re-usable infrastructure.
- As the term is used in the published literature, "depleted field storage" encompasses a wide range of scenarios including post-production storage in a former hydrocarbon reservoir, syn-production storage in the water leg of a hydrocarbon reservoir, and CO_2-EOR.
- Pure storage operations and CO_2-EOR operations have some operation similarity, but have substantially different motivations and different regulatory maturity in different regions. In the US, CO_2-EOR offers more mature regulation and easier permitting. In the EU, post-production storage has greater regulatory maturity and has been the primary choice of EU depleted field storage projects.
- In all projects, outreach and public relations are important, even critical. Early stakeholder engagement is key.
- Storage projects completed to date have proven and extended the science and developed a wide range of monitoring tools to assure storage security. All have their merits but their cost effectiveness varies depending on project specifics, particularly the surface environment, the presence of hydrocarbons above the storage reservoir and project-specific concerns.
- Sub-hydrostatic reservoir pressure is a sign of closed or semi-closed reservoir boundaries. Such reservoirs may offer greater storage security but also place sharp limits on capacity by limiting the propagation of injection pressure
- The presence of remaining hydrocarbon gas in place does not negatively affect the CO_2 storage capacity of the depleted dry gas reservoirs, other than occupying pore space.
- The large density and viscosity contrast between CO_2 and methane limits the mixing of the two, leading the CO_2 plume to be mainly accumulated at the bottom of the reservoir at the post-injection stage. The gas (methane) layer forming below the reservoir top may act as a barrier, lowering the risk of CO_2 plume migration towards the top seal and hence improving the CO_2 storage integrity in a depleted dry gas reservoir.
- While storing CO_2 in a depleted dry gas reservoir, the majority of CO_2 plume remains mobile, while capillary and dissolution trapping mechanisms play minor roles in trapping the CO_2 plume.
- Beyond occupying pore space, the amount of remaining gas (methane) in place does not significantly affect the capillary and dissolution trapping efficiency of CO_2 plume in a depleted dry gas reservoir.
- It should not be taken as guaranteed that infrastructure reuse will always result in lower costs for CCS projects.

- For a hypothetical base-case CO_2 storage project size of 1 Mtpa and a 50-kilometer pipeline length, the total project cost is most sensitive to pipeline costs. Reuse of existing pipelines can save significant cost but depends on a number of variables, chiefly capacity, pressure rating and condition.
- In contrast to hydrocarbon exploration where the goal is to maximize discovered reserves, current and planned storage projects are typically driven by the need to abate specific emissions sources and therefore have well defined requirements that can be met in a variety of ways. As long as a storage site meets project requirements, bigger is not necessarily better.
- Published criteria for evaluating depleted fields identify many of the key factors but definition of favorable and unfavorable ranges for all variables creates a long list that fails to recognize both the relationships between them and the potential for excellent overall results from a variety of combinations that may include individually sub-optimal parameters.
- We recommend that screening focus on five overarching factors: capacity, injectivity, containment security, reusable infrastructure and public/regulatory acceptance. These factors have multiple inputs which combine to create flexibility in how to meet project requirements.
- The report details the criteria to efficiently screen for needed capacity, injectivity, containment security, reusable infrastructure and suitability for CO_2-EOR. Capacity and injectivity are presented as graphs, offering efficient order-of-magnitude evaluation.

1. Introduction

In this review we consider advantages and disadvantages of using depleted fields in comparison to deep saline reservoirs as CO_2 storage sites. In concept, depleted reservoirs offer several advantages: first, hydrocarbon reservoirs have proven themselves capable of retaining buoyant fluids over geologic time, thereby partially de-risking the geologic container for CO_2. Second, historic net production volumes are indicative of storage capacity and together with the extensive subsurface datasets common in depleted fields, they can greatly reduce the geologic uncertainty. Third, and perhaps most important, is economics. Being able to take advantage of existing infrastructure and subsurface characterization data could offer reduced costs and accelerated project timelines. Learnings from oil and gas exploration and production, including injectivity, pressure response, and reservoir architecture are directly applicable to CCS.

The history of oil production now spans more than 150 years and the number of depleted fields potentially available for CCS is large. Mature petroleum basins such as the North Sea, the Gulf of Mexico and Bohai Bay (northeast China) may have tens or even hundreds of depleted fields, each with its own dataset, production history and legacy infrastructure. While there is clear attraction to repurposing depleted fields, the process of evaluating and ranking them is not trivial. A wide variety of studies have looked at re-using depleted reservoirs and together they create a significant library of case studies (e.g., Chiaramonte et al., 2008; Doughty et al., 2008; IEAGHG, 2009, 2017, 2018; Brennan et al., 2010; Godec et al., 2011; Whittaker et al., 2011; Total, 2015; ETI, 2016; Hannis et al., 2017).

As is often the case however, reality is messy and few, if any of the potential positives relating to storage in depleted fields are unambiguous, universal advantages. Proven reservoirs and seals may not be large enough or have high enough injectivity to support injection at industrial rates. Data may have been lost, become unreadable, or in the case of old fields, may never have been acquired. Global infrastructure has a wide range of age, design specifications, engineering practice and remaining life. In concept, infrastructure utility for a new role in CO_2 storage likely ranges from genuine asset to net liability. Broad, low-relief structures may not reduce the monitoring footprint compared to a greenfield saline aquifer storage site. Community experience with past oil field practice may not translate to willingness to accept CO_2 injection.

This report is motivated by trying to examine these factors and create a framework for evaluation of depleted fields. It is presented in three sections. The first section looks at a series of case studies, chosen with a bias toward those with operational experience and illustrating the reality of repurposing old fields. It includes both reuse for storage and reuse for CO_2-EOR (with significant incidental storage). The second section presents original research on potentially under-recognized sensitivities—parameters that might involve trade-offs not recognized in previous studies on screening criteria. Specifically, the second section looks at reservoir pressure depletion and boundary conditions, the effect of residual hydrocarbons on injectivity and capacity, and the net value of existing infrastructure as compared to building it anew. The last section attempts to discuss and integrate the emerging insights to facilitate evaluation of future depleted field storage opportunities.

2. Case Studies

2.1. Introduction

Case studies offer valuable learning opportunities, where theories get tested and blind spots become apparent. Ten such studies are presented here and they serve to frame the following discussions and ground them in experience. These cases are chosen to illustrate the ranges of storage in depleted fields, from pilot research projects to large-scale commercial ventures, from EOR to pure storage and from injection directly into the field to down-dip injection in the water leg. While many more possibilities have been studied, we have biased our choices toward those with some form of operational experience (Figure 1, **Error! Reference source not found.**). The one exception to that is Altmark, which we have included for the insights it offers on public perception and regulatory approval.

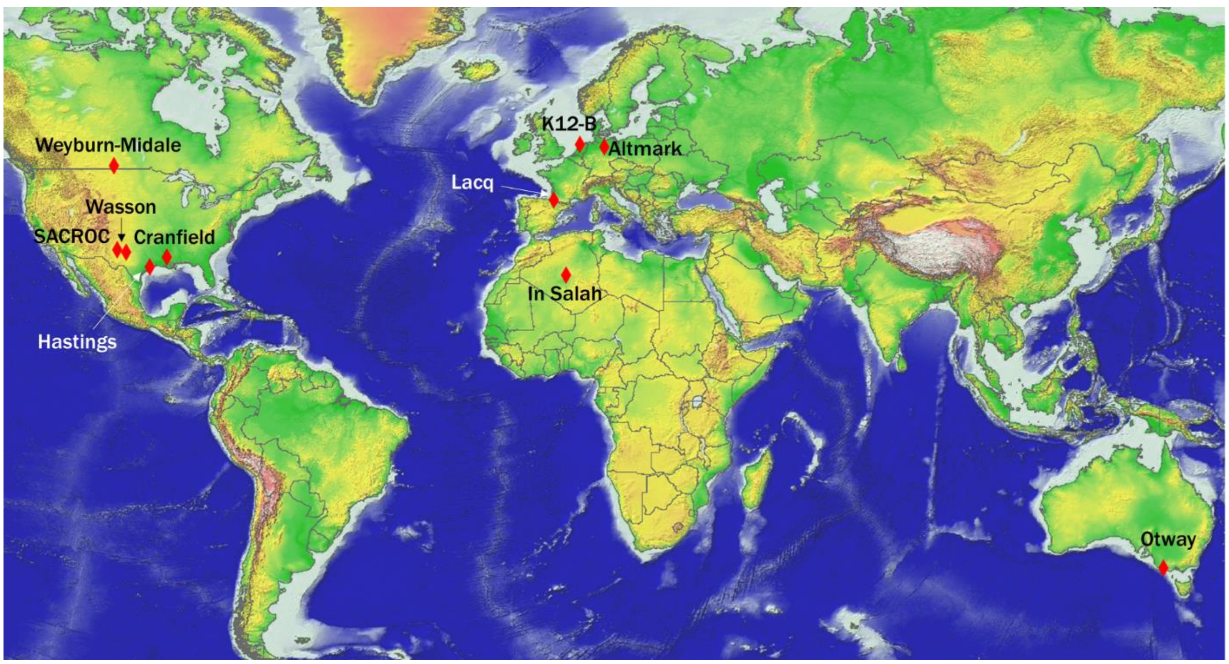


Figure 1: Locations of case studies presented here.

Name			Location			Field Characteristics				CCS	
Field	CCS Project	Operator	Country	Basin	onshore/ offshore	Depth (m)	Reservoir type	HC phase	HC production status	Carbon storage scheme	CO_2 stored to date
Rousse	Lacq Pilot Project	Total	France	Aquitane	onshore	4200	carbonate	gas	depleted	post-production	51kt
Naylor	CO2CRC Otway Project	CO2CRC Pilot Project Ltd	Australia	Otway	onshore	2050	clastic	gas	depleted	post-production	65kt
Weyburn-Midale	Weyburn-Midale CO2 Project	PCOR Partnership	Canada	WCSB	onshore	1400	Carbonate	oil	active EOR	EOR	~30Mt
SACROC (Kelly-Snyder Field)	Southwest Partenrship Ph II	Kinder Morgan	United States	Permian	onshore	6700	Carbonate	oil	active EOR	EOR	~80Mt
Cranfield	SE Reg. Parternship "Early" test	Denbury	United States	Gulf of Mexico	onshore	3100	clastic	oil	active	syn-production	5.37Mt in test, exculding EOR
K12-B	K12-B	GPN	Netherlands	Southern Permian	offshore	3800	clastic	gas	depelted	syn-production	100kt
Krechba	In Salah	In Salah Gas JV	Algeria	Ahnet	onshore	1800	clastic	gas	active	syn-production	3.8Mt
Hastings	Hastings	Denbury	United States	Gulf Coast	onshore		clastic	oil	active EOR	EOR	~7Mt
Wasson	Wasson Denver Unit	OXY	United States	Permian	onshore	4900	carbonate	oil	active EOR	EOR	144Mt (Denver Unit only)
Altmark	Project CLEAN	GDF SUEZ E&P	Germany	Southern Permian	onshore	3400	clastic	gas	depleted	post-production	0Mt (permit appl. rejected)

Table 1: Summary of case studies presented here. Data sources are given in the text.

2.2. Altensalzwedel sub-field, Altmark gas field

With a heavily industrialized economy, the sixth-highest CO_2 emissions in the world, and European Union social and regulatory pressures to decarbonize, Germany has strong incentives to investigate the possibilities for CCS despite a long-standing opposition to onshore CO_2-storage. Project CLEAN was a research and development (R&D) project that ran from July 1, 2008, to December 31, 2011, building on earlier modeling studies (Rebscher and Oldenburg, 2005; Kühn et al., 2012). The project was funded by the German Federal Ministry of Education and Research and was coordinated by the GFZ (German Research Center for Geosciences) at the Helmholtz Centre Potsdam. The research had two main objectives. First, the research was designed to test the possibility for CO_2-enhanced gas production (EGR) from a Rotliegend reservoir that was unsuitable for other means of stimulation. Second, it aimed to test the suitability of the Altmark gas field for CO_2 sequestration. The work was divided among 16 partners from academia and industry, including the field operator, GDF SUEZ. Research was divided into three themes: well integrity, evaluation of geologic processes, and environmental and process monitoring (Kühn et al., 2012).

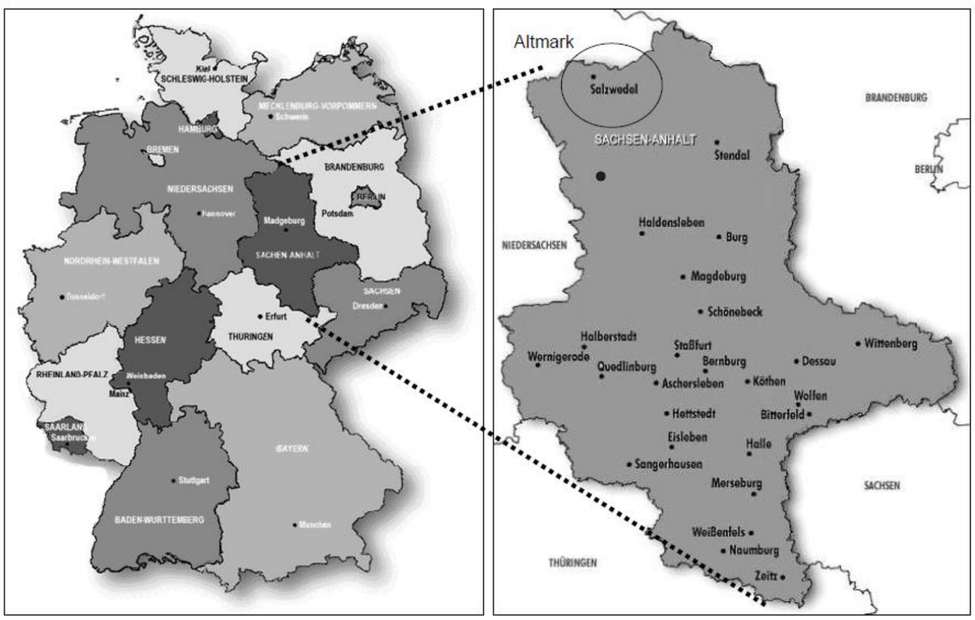


Figure 2: Location of the Altmark fields (Rebscher and Oldenburg, 2005).

The Altmark gas field is located in north Germany in the state of Sachsen-Anhalt (Figure 2). The trap is a broad, faulted anticline (Figure 3) that is divided into nine sub-fields, of which the Altensalzwedel (or Salzwedel-Peckensen, as it is also known) is the most important (Rebscher et al., 2006; Kuhn et al., 2012). The crest of the gas-bearing reservoirs is at 3135 m depth, with the gas–water contact at 3442 m. The reservoir itself is the Lower Permian Rotliegend formation, consisting of 226 m of sandstones, siltstones, and claystones deposited in fluvial and aeolian environments. Effective porosity averages 8% and permeability is generally in the range of 10–100 mD, with local variations as extreme as 0.5–1000 mD (Figure 4). Containment is provided by several hundred meters of Zechstein evaporites, deposited in a sabkha setting (Rebscher and Oldenburg, 2005; Rebscher et al., 2006).

The field was discovered in 1968 with 9 Tcf of gas in place (GIP), making it the largest gas field in Germany and one of the largest in Europe. By 1999, 70% of the gas had been produced and production was in decline, with complete depletion projected by 2020 (Figure 5; Rebscher and Oldenburg, 2005 and references therein). The bounding faults effectively seal the reservoir from the surrounding aquifer, at least on production timescales such that reservoir pressure in the Altensalzwedel block dropped from 42.5 MPa at the time of discovery to 3–5 MPa by 2011 (Kuhn et al., 2012) with 78% recovery factor (Ganzer et al., 2014). More than 400 wells were drilled into the field during that period, 93 of which were actively producing from the Altensalzwedel block in 2001 (Rebscher and Oldenburg, 2005).

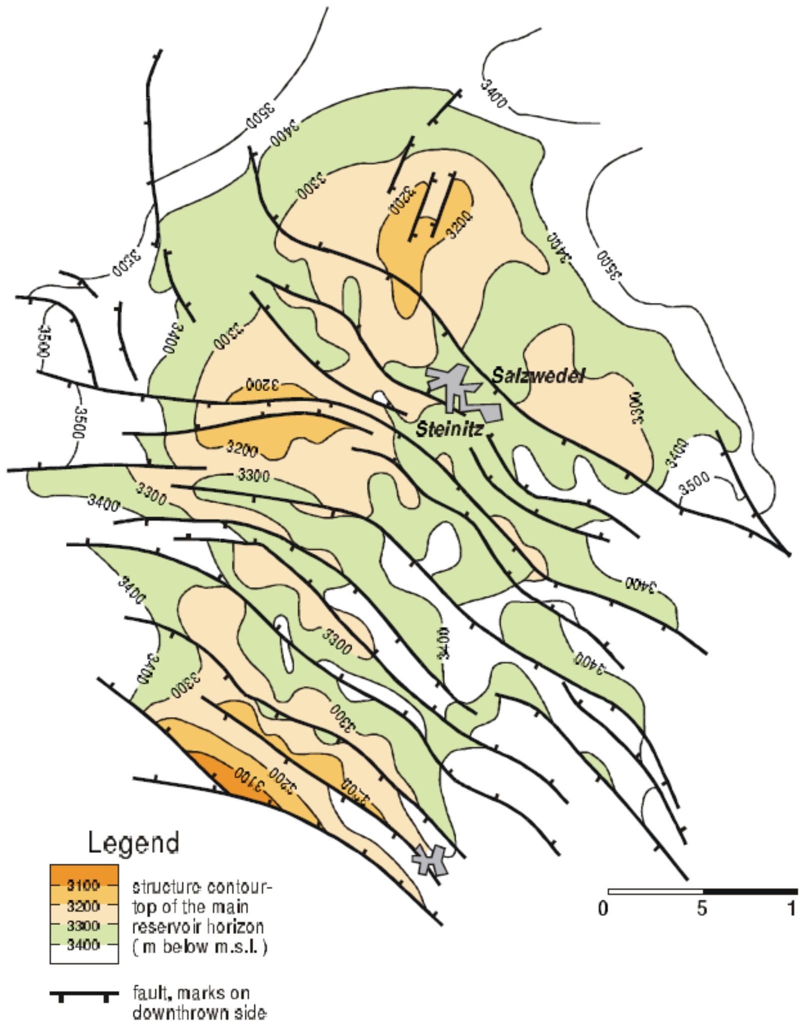


Figure 3: Structure map on the top of the main Rotliegend reservoir horizon. Note that faults compartmentalize the structure (Rebscher and Oldenburg, 2005).

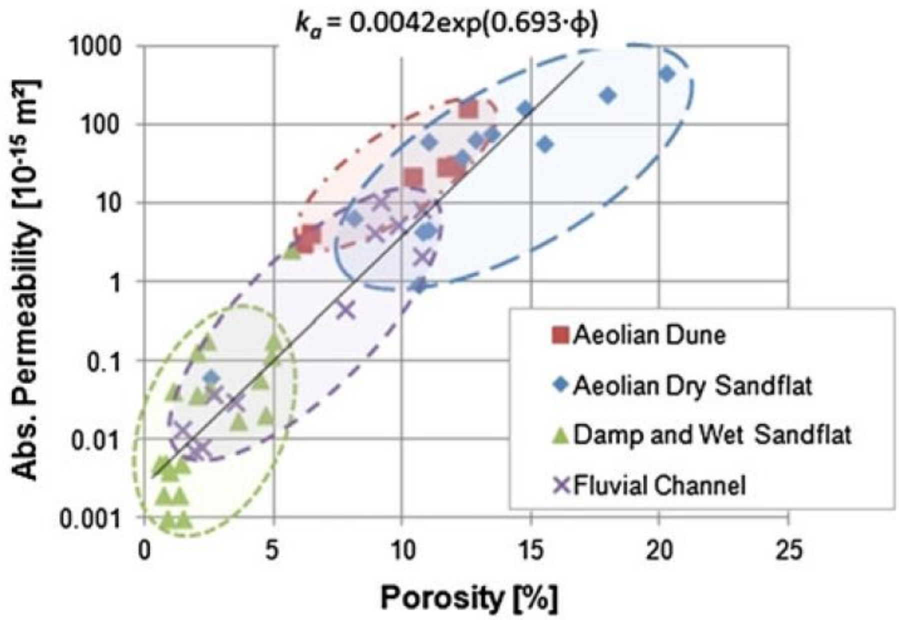


Figure 4: Porosity–permeability relationships for the main reservoir facies (Ganzer et al., 2014).

When Project CLEAN kicked off in 2008, the intent was to perform a series of studies, leading up to and focused around injection of 100,000 tons of CO_2. A variety of characterization, modeling, and laboratory studies were performed as planned and GDF SUEZ, the site owner and operator, built the injection facilities, obtained the necessary materials and trained staff. However, the project faced public opposition almost from the beginning, and ultimately the regulators declined to issue an injection permit. As a result, many of the operational aspects of the project were never realized. Nevertheless, useful results emerged from the studies that were performed, and the process of public interaction offers valuable insight for future projects.

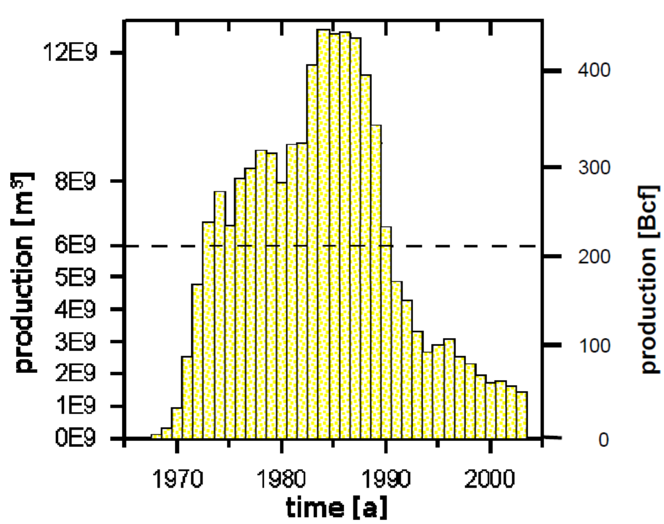


Figure 5: Hydrocarbon production of the Altmark natural gas fields. Dashed line shows average annual production (Rebscher and Oldenburg, 2005).

Three research results stand out:

1. The wide variation in natural reservoir permeability suggests a highly uneven flow of CO_2. High permeability streaks create preferential flow paths from injectors to producers, severely limiting the sweep efficiency and thus the effectiveness of EGR. Models using pre-injection of water or gelling fluids to reduce the highest permeabilities show only modest improvement in time for CO_2 to break through. With no intervention, modeled CO_2 took 2.5 to 10 years to reach producing wells, depending on the values assigned to the highest-permeability streaks. In both cases, sweep was incomplete. Experiments injecting water with and without viscosity-enhancing gels offered only incremental improvements. Injecting water for 5 to 10 years prior to CO_2 injection, while simultaneously producing gas, did indeed saturate the high-permeability streaks. However, it only delayed the simulated breakthrough of CO_2 by about a year. Partly, CO_2 injection displaced water, partly the presence of water decreased the pore space available for CO_2 (and therefore increased CO_2 flow velocity), and partly water tended to drain downward due to gravity. Adding viscosity-enhancing gels seemed promising, but model results showed a delay in breakthrough times of only a few months compared to water alone (Rebscher et al., 2006; Ganzer et al., 2014). Last, it is worth noting that while poor sweep efficiency creates challenges for EGR, all model experiments suggested an ultimate CO_2 storage capacity of millions of tons, one to two orders of magnitude greater than the 100,000 ton goal of Project CLEAN (Rebscher and Oldenburg, 2005).
2. With hundreds of legacy wells in the field, the potential for CO_2 leakage behind pipe was cause for concern. On the other hand, evaporite minerals (including those composing the Zechstein seal) have a high creep rate, raising the possibility of healing voids in the cement–rock interface. Full-scale experiments were run to test that possibility, using steel pipe cemented in natural Zechstein rock samples mined from northern Germany. Somewhat surprisingly, in the 60 days of the experiment, healing was observed not only at the cement–rock interface but even within the cement and at the cement–pipe interface. Further experiments looked at potential operational measures to heal defects in the casing or at the casing–cement interface. A catalog of interventions was compiled, including the injection of gels, emplacement of secondary cement jobs, and the application of patches (Kühn et al., 2012).
3. Monitoring of injected CO_2 is a key part of any sequestration project, and CLEAN experimented with a variety of possible methods. Without actually injecting CO_2, these were limited to baseline studies and modeling. Of particular note is the work on seismic detection of CO_2. The likelihood of diffuse flow in a gas-bearing reservoir limited the potential for 4D seismic to image the CO_2 plume. However, research highly recommended focusing repeat surveys on the aquifers above the reservoir, as even small amounts of CO_2 in brine would create large changes in acoustic impedance contrast and should therefore be highly visible on repeat surveys. Additionally, work on passive seismic monitoring resulted in an algorithm for the automated detection and location of seismic events that could be useful in rapidly distinguishing injection-related seismicity from natural events (Kühn et al., 2012).

Perhaps the greatest insights from Project CLEAN are not the technical insights however, but the operational aspects of public relations and permitting. Public-information events were held early in the project and contact was made with local politicians, but delays in communication followed as the proposed project ran into opposition and the project consortium fell into disagreement over communications strategy. The gap in communication effectively ceded the stage to project opponents, leaving them as the dominant voice in the public debate. Post-project interviews with a wide variety of stakeholders indicated that the perceived risks outweighed the benefits. Specifically, the public generally recognized the project's potential contribution to mitigating climate change and it's potential to benefit the local economy, but they also feared risks to humans and animals, the potential negative competition for renewables, risks to drinking water, and bad publicity for the region (Kuhn et al., 2012; Dütschke et al., 2015).

As discouraging as this result was, it was not unusual in Germany at the time. Out of four fairly similar project proposals (including Altmark), only one (Ketzin) received permission to proceed with injection. All of the others met with public protest and were ultimately canceled prior to injection. Looking at the common factors gives some idea of the possible reasons for failure. First, the scale of the project may matter. The three canceled projects either planned industrial-scale injection or had the potential to expand to industrial-scale. Only Ketzin was clearly limited in scope. Second, timing and perceived intent of communications with the public seems critical. As described, Altmark began communications early in the project but lost the momentum. Similarly, the other two blocked projects also opened communications with the public during the permitting process, in one case as part of the official permit hearings and in the other at the time the permit application was submitted. In both cases, this seems to have created the perception of a done deal rather than a consultation with the public. Public relations campaigns that were perceived to be overly positive about CCS probably did not help, either. Only Ketzin, the lone successful project, began communications with the public prior to any specific project planning and created information campaigns in parallel with project development (Dütschke et al., 2015).

In fairness to the three cancelled projects, only about half of the German public had any awareness of CCS, and attitudes toward it were strikingly negative. Nationwide surveys revealed that while 75% correctly identified CO_2 as a greenhouse gas, 52.6% thought it was poisonous (note that CO_2 concentration was not part of the question), 20% thought it was flammable, 19% thought it was explosive, and 20% identified it as a water pollutant. When asked for a preference among 3 options for CO_2 storage location, fully 40% of respondents volunteered either "I don't care" (9%), "Nowhere" (25.6%) or "Elsewhere" (2.8%). These responses are particularly noteworthy as they were not among the options offered and were only recorded when survey participants volunteered them (Dütschke et al., 2015).

In summary, the Altmark Project CLEAN achieved some notable technical insight but fell short of its initial goals, not because of technical problems but because of communications and public opposition. In a technical-research field dominated by scientists and engineers who are already convinced of the merits of their work and focused on technical questions, public relations are easily overlooked until late in the process. Altmark suggests that may be a serious mistake.

2.3. K12-B

The K12-B gas field was discovered in 1982 on the Dutch continental shelf, about 150 km northwest of Amsterdam (Figure 6). The accumulation was trapped in a series of fault-bounded compartments within a larger tilted fault block at 3800 m depth (Figure 7). The reservoirs are a complex interfingering of fluvial and aeolian facies of the Upper Slochteren Member of the Rotliegend sandstone. High-permeability aeolian deposits (30–500 mD) are interbedded with low-permeability fluvial facies (5–30 mD) and mud-flat deposits that form vertical flow barriers. Average permeability is only 2–10 mD, but local streaks reach as high as 1000 mD. Repeated cycles of Zechstein evaporites provided a robust seal. Bounding faults completely separate individual compartments from each other and from aquifer support (Vandeweijer et al., 2011; Van der Meer, 2013).

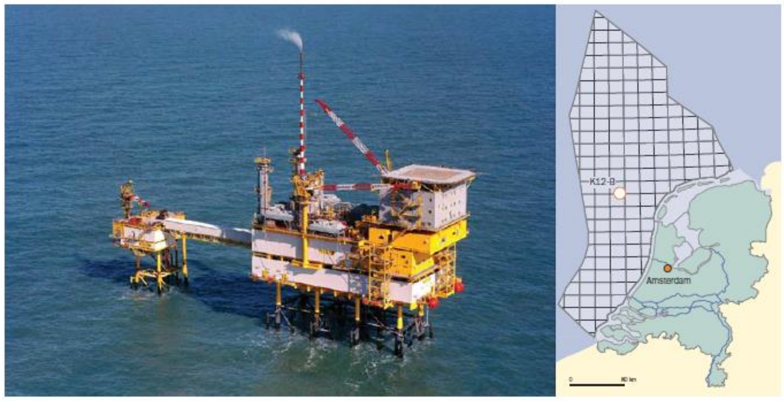


Figure 6: K12-B platform and map showing field location (TNO, 2007).

Production began in 1987 via eight wells and two bridge-linked platforms. The gas contained 13% CO_2, which was separated on the platform to meet the pipeline export specification of less than 2% CO_2. At a daily production rate of 300,000 cubic meters (10.6 mmscf), this resulted in about 60 tons/day of CO_2 vented to the atmosphere (Van der Meer, 2013). In 2002, the Dutch Minister of Economic Affairs published a subsidy for studies on the feasibility and implementation of CCS in response to the Kyoto Protocol. K12-B was identified as an opportunity to pilot CO_2 capture and injection and investigate the feasibility of future industrial-scale CO_2 sequestration in depleted fields. Reinjection of the separated CO_2 stream began in late 2004, using an existing production well converted to an injector. Initially, CO_2 was injected into Compartment 4 via the K12-B8 well (see Figure 7). That compartment was nearly depleted, and the well cycled between injection and production. In 2005, injection switched to Compartment 3 and the K12-B6 well. That well is located at the crest of the structure and is one of three in the compartment. Gas production continued from the remaining two wells, located on the flank of the structure. Operations continued through multiple phases of study until complete depletion of the field in 2017, at which point the end of production halted the supply of CO_2 and effectively ended the studies (Figure 8). In total, about 115,000 tons of CO_2 were stored over the 13 years of injection (Vandeweijer et al., 2018), equal to the volume of CO_2 produced over the lifespan of the project, minus relatively small amounts vented during mechanical interventions (Van der Meer, 2013). For comparison, total field storage capacity was assessed as 25 Mt (Van der Meer, 2013). Total production volumes are unpublished, but a 2011 paper notes that at that time, the field had produced over 12 Bcm (424 Bcf), or about 90% of the initial gas in place (Vandeweijer et al., 2011).

As a pilot project, CO_2 injection was heavily monitored. First, concerns about the potential for corrosion and uncertainty about downhole conditions prompted intensive surveillance of the injection wells, looking for changes in integrity. Second, interest in possible future CO_2 EGR projects and related questions about sweep efficiency gave rise to significant efforts to understand migration in the reservoir.

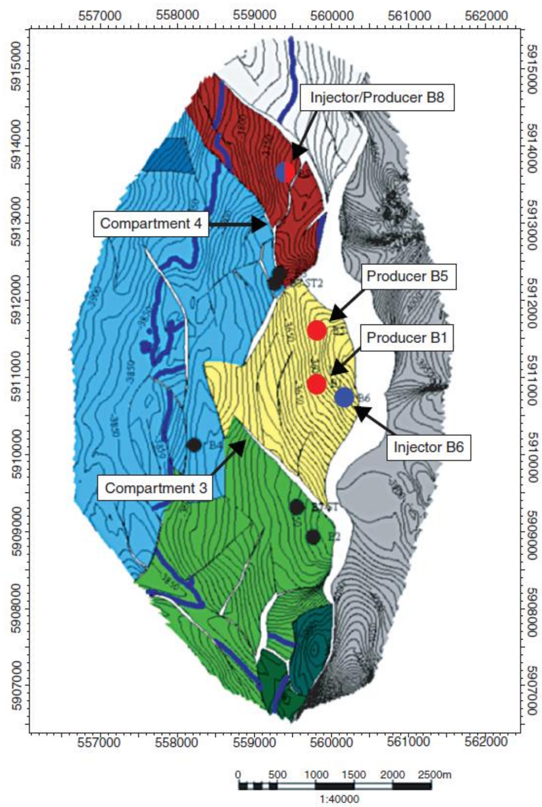


Figure 7: Map of the K12-B field showing fault-bounded production compartments and location of wells. Dark blue line shows the original gas–water contact (Van der Meer, 2013).

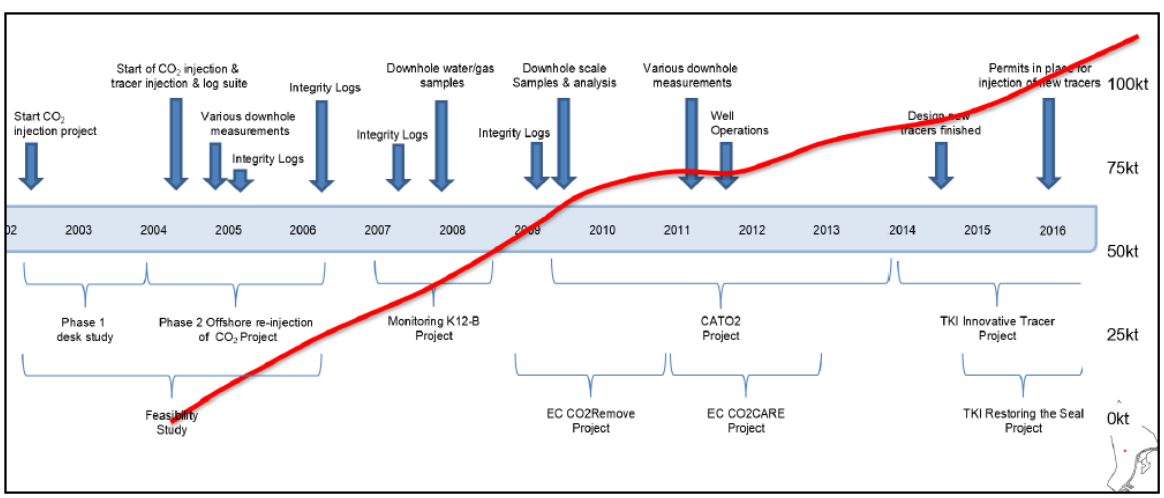


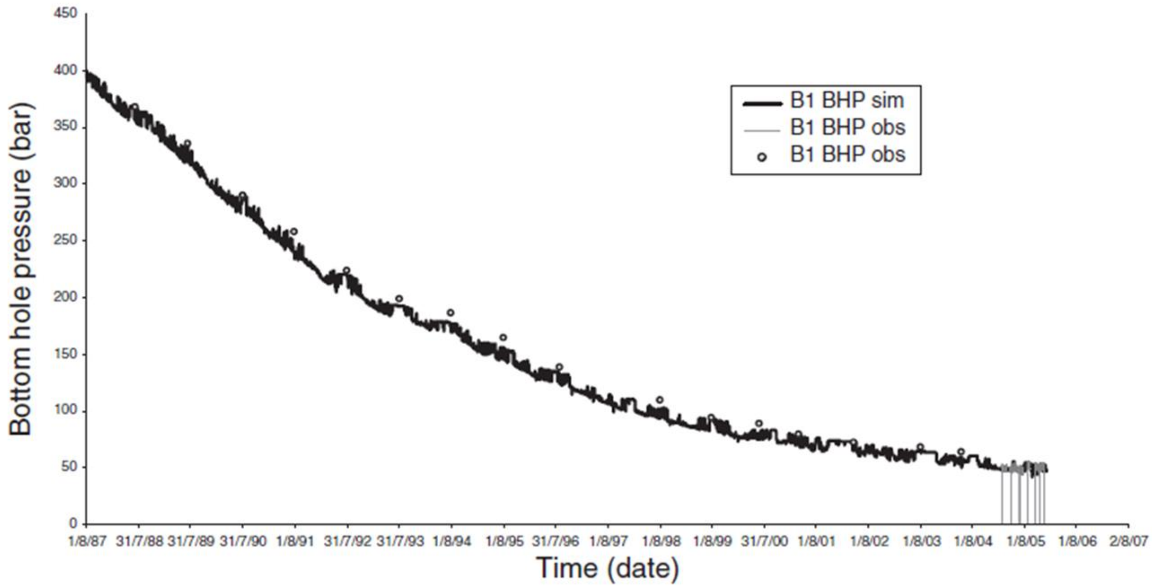
Figure 8: K12-B CO_2 injection project timeline, showing major studies. Red line shows cumulative mass of CO_2 injected (Vandeweijer et al., 2018).

With little or no water content, the injected gas was considered non-corrosive. However, repeat caliper log surveys in 2005 and 2006 showed significant variation in well-bore diameter that was interpreted as pitting of the steel, up to 25% of the original thickness. A Cement Bond Log (CBL) run also failed when the tool encountered a previously unknown downhole obstruction. Subsequent downhole video logging in

2007 suggested that the cause of both the “pitting” and the failed CBL run was actually accumulated scale from gas production, with the largest variations caused by the tracks of the caliper tool and possibly cable drag. Samples of the scale revealed that it was composed mainly of two phases of crystalline barite, precipitated out of the produced fluids as a result of temperature drop in the wellbore. Further caliper surveys in 2007 and 2008 showed pipe diameters similar to the first run in 2005. Follow-up logging in 2009, using Schlumberger’s then-experimental Electromagnetic Imaging Tool (EMIT), showed very consistent pipe integrity over the entire logged interval (Vandeweijer et al., 2011). In a discussion of lessons learned, Vandeweijer et al. (2018) noted that in the end, repurposing an existing well, with 20 years of wear and tear, had significantly hindered monitoring.

To look at CO_2 behavior in the reservoir, pressure and produced-gas composition were constantly monitored and two types of perfluorocarbon tracers were injected with the CO_2 in 2005, followed by regular sampling and analysis of the fluids from the two production wells. Those particular tracers were chosen as they mimic the behavior of methane and therefore offers insight into the flow of CO_2-driven gas in the reservoir. Breakthrough occurred after 130 days at the closer producer (K12-B1, ~420 m away) and after 463 days at the farther producer (K12-B5). CO_2 concentration rose steadily in the K12-B1 well, from 13% in 2005 at the onset of injection to over 25% in 2010. Over the same period, CO_2 concentration in the produced fluids from the more distant K12-B5 well remained unchanged at 13%. Dynamic reservoir modeling concluded that (1) these results were within the range of expected behavior and that available modeling tools were sufficient for use with CO_2; and that (2) CO_2 injection did not affect the permeability of the reservoir (Vandeweijer et al., 2011).

Interestingly, bottom hole pressure (BHP) measurements in the injector and the nearest producer showed a consistent and striking difference. At the bottom of the injector, pressure consistently exceeded 100 bars, whereas it was less than 50 bars at the bottom of the nearest producer, 420 m away (Figure 9). Both wells were in the same compartment, with no known barriers between them. Tracers and produced-gas composition prove communication and the reason for the pressure difference is unclear (TNO, 2007).



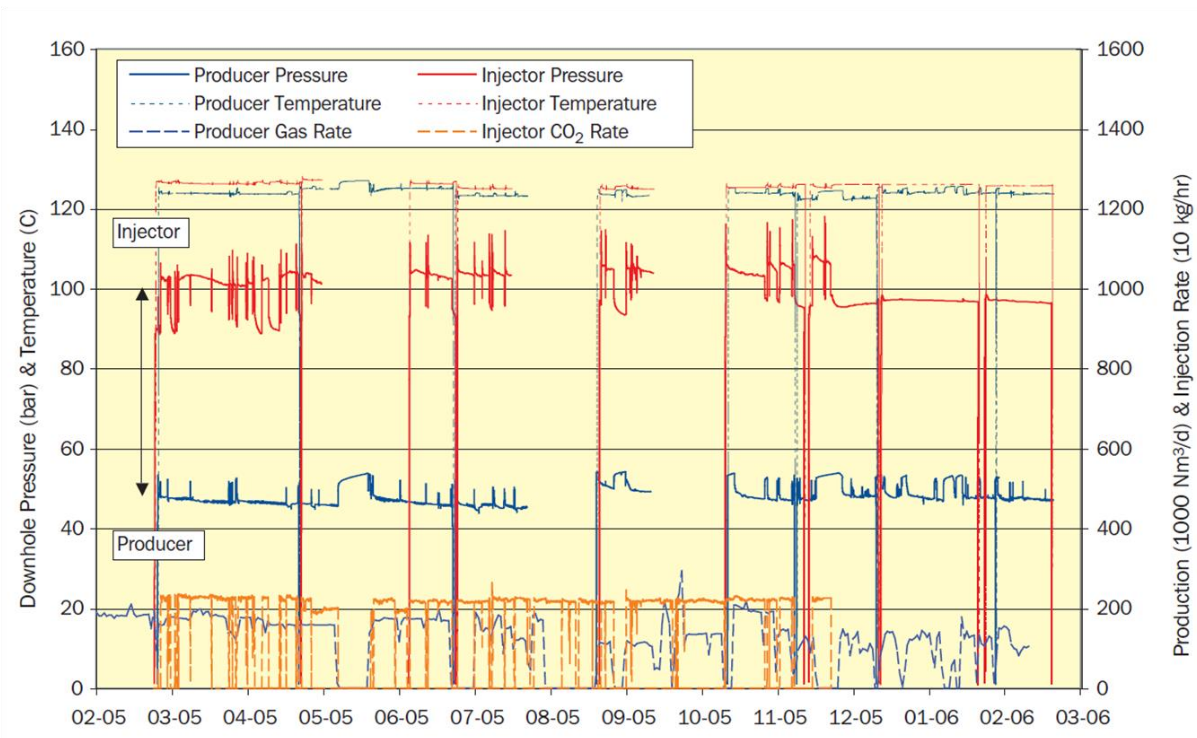


Figure 9: Pressure evolution of the K12-B field. Top figure shows BHP in well B1 from the onset of production in 1987 through the first CO_2 injection in 2004–2005 (Van der Meer, 2013). Bottom figure shows a comparison of BHPs between producer (well B1, solid blue line) and injector (well B-6, solid red line) over two years of operations (TNO, 2007). Both wells are in the same fault-bounded compartment, only 420 m apart, with no known barriers between them. The cause of the pressure difference is unknown.

2.4. In Salah

The In Salah gas development is a collection of gas fields in the Sahara Desert of Algeria (Figure 10). They were discovered and appraised in the 1970s and 1980s to have a total estimated recoverable resource of 159 billion cubic meters (5.7 Tcf) in three main fields: Tegentur, Reg, and Krechba. In the early 2000s, Sonatrach, BP, and Equinor formed a joint venture to develop the fields as a cluster (Davis et al., 2001). However, the gas contained 1%–10% naturally occurring CO_2 and the gas-export specification was 0.3% or less. Thus as part of the project design, the partners pledged to separate and reinject the produced CO_2 into the water leg of the single largest field, Krechba, in the world's first commercial-scale onshore CO_2 storage project (Riddiford et al., 2003; Shi et al., 2019). Specifically, the partnership aimed to achieve the following:

Figure 10: Location of the In Salah gas field and CCS project.

1. Create assurance that secure geologic storage could be cost-effectively monitored and that short-term monitoring could assure long-term security.
2. Prove to stakeholders that geologic storage was a viable means of greenhouse gas (GHG) reduction.
3. Create a precedent for the regulation and assurance of geologic CO_2 sequestration, such that it could be eligible for GHG credits (Ringrose et al., 2013).

The Krechba field is a gentle anticline cut by a number of faults. Formed in Carboniferous time by the compressional inversion of a Cambrian graben, it was subtly faulted under continued compression. Uplift during the Hercynian orogeny removed a significant amount of overburden, relaxing the stress and forming northwest–southeast-trending joints. None of the faults cutting the field fully offset the reservoir, and it is therefore often described as "relatively unfaulted," which is perhaps misleading as fluid flow is heavily influenced by faults and natural fractures (Davis et al., 2001; Ringrose et al., 2011; Bjørnarå et al., 2018). Present day, the field sits at 1900-m depth in a strike-slip stress regime with a northwest–southeast maximum compressive stress, which tends to open the natural fractures (Ringrose et al., 2011; Shi et al., 2019).

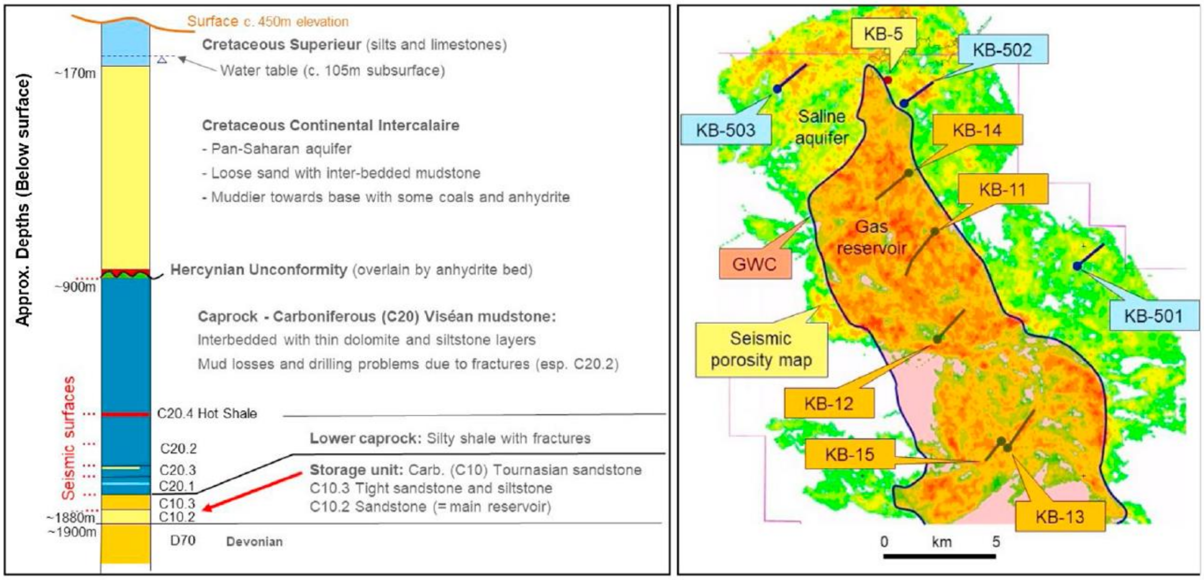


Figure 11: Stratigraphic column and map showing seismic porosity, the outline of the gas reservoir, and the location of gas production wells (orange) and CO_2 injection wells (blue). Figure from Shi et al., 2019.

The reservoir is the Carboniferous C10.2 sand, deposited in estuarine to deltaic environments. Within the field, its thickness varies from 5 to 24 m, with around 20 m of net sand on average (Davis et al., 2001; Ringrose et al., 2011). It is a clean quartz-arenite sand but well cemented and brittle, with an average matrix porosity around 15% (Bohloli et al., 2018). In detail, cementation is highly variable, with chlorite grain coatings preserving porosity in some locations and extensive quartz cementation largely destroying it in others (Ringrose et al., 2011). Matrix permeability is low, on average 0–10 mD, but natural fractures contribute significantly. Modeled fracture permeability is 150–350 mD, possibly even as high as 1000 mD under favorable stresses (Durucan et al., 2011; Ringrose et al., 2011; Bohloli et al., 2018).

The seal is composed of two parts. Immediately overlying the reservoir is a tight sandstone/siltstone, the C10.3 formation, 20–25 m thick. Above that is a ~900-m section of Carboniferous mudstones interbedded with thin dolomites and siltstones (Figure 11) (Shi et al., 2019). Together, these units form the containment system for the Krechba reservoir.

Prior to development, the key uncertainties identified at Krechba were reservoir distribution and quality, the exact depth of the gas–water contact, well performance, gas saturation, and depth structure (Davis et al., 2001). Accordingly, an intensive data-acquisition program was undertaken, mostly aimed at reducing production-related uncertainty but with some components targeting injection, including a baseline 3D seismic survey, shallow aquifer sampling, headspace gas sampling in the overburden throughout the field, and extensive logging of the three injection wells. These were drilled on the northern and eastern sides of the field, down-dip of the gas–water contact. In view of the relatively thin, low-permeability matrix, the injectors were constructed with long horizontal sections in the reservoir, oriented perpendicular to the dominant fracture trend, aiming for maximum injectivity (Ringrose et al., 2013; Bjørnarå et al., 2018). Injection began in 2004 and continued until 2011, storing over 3.8 Mt of CO_2 in total. Injection was heavily monitored, including the use of 4D seismic, InSAR (interferometric synthetic aperture radar), microseismic, CO_2 tracers, continuous wellhead pressures, shallow aquifer monitoring, and surface flux measurements.

The central challenge of injection became managing the balance between achieving the injection rates needed to sequester the separated CO_2 and over-pressuring a tight reservoir. Prior to injection, reservoir pressure was 17.5 MPa with a fracturing pressure of ~28.6 MPa. Bissell et al. (Bissell et al., 2011) estimated that the cooling effect of injection might have reduced that by 1.5–5 MPa over the first six months of injection, leaving a relatively narrow window of safe injection pressures. Much has been written about this balance, documenting injection pressures that exceeded fracturing pressure at all three injection wells (Figure 12) and we will not attempt to reproduce that literature here. In brief, a distinct two-lobe uplift pattern was noted above the KB-502 injector and subsequently interpreted as the result of propagating a 4-km-long tensile fracture zone extending 40 m above and below the reservoir (Vasco et al., 2010). Subsequent history matching with reservoir models and suggested that ~25% of the injected CO_2 could have migrated vertically into the lower parts of the containment system (Shi et al., 2019). No analyses have suggested that the containment system was breached however. By contrast, history matching at the other two injection wells also showed periods of injection above fracturing pressure and periods of both matrix and fracture flow in the reservoir but no evidence for the creation of new fractures.

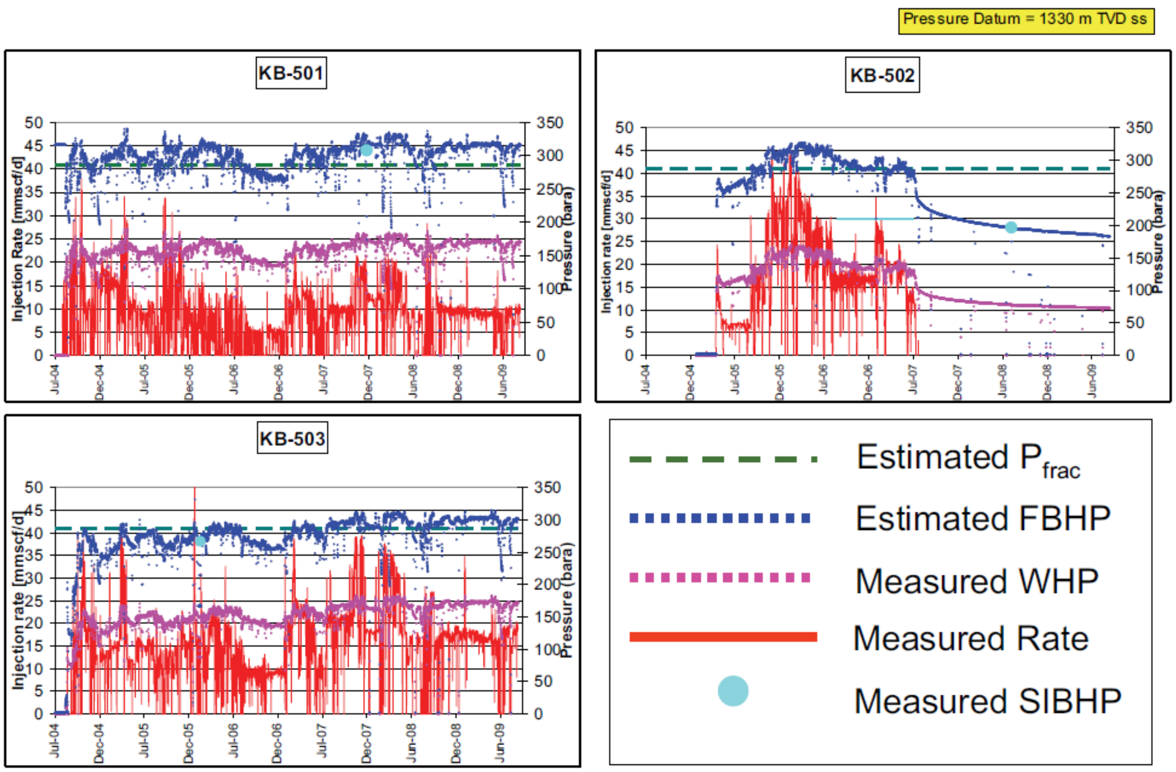


Figure 12: Pressure measurements and injection rates from the three injection wells for 2004 through 2009, along with the estimated fracturing pressure in the reservoir (Bissell et al., 2011).

In response to the evidence of fracturing and the attendant risk of CO_2 migrating either vertically into the containment system or horizontally out of the field, well KB-502 was shut in for two years during which a new seismic survey was acquired, micro-seismic monitoring was installed above the horizontal section of KB-502 and further monitoring and analysis were carried out (Ringrose et al., 2013). Following review, injection resumed in 2010 at reduced pressure. Even so, the newly installed micro-seismic array recorded a steady stream of events, including two peaks of 20 to 40 events per day during two periods when injection pressure again exceeded fracturing pressure (Oye et al., 2013). Injection ended in 2011.

In a 2013 review, Ringrose et al. (Ringrose et al., 2013) identified InSAR, 3D seismic, microseismic data, and wellhead sampling with CO_2 tracers as the most valuable of the deployed monitoring tools. As always, these were most valuable when integrated and jointly inverted to constrain subsurface interpretations. Surveillance of shallow aquifers and soil gas flux showed no anomalies. The authors also highlighted the varying data needs as the project progressed, from structural geologic characterization and rock mechanics early in the project to pore-space and fluid-flow data as the project progressed. The project also highlighted the need for fracture characterization and the operational challenges of dealing with a very low permeability reservoir.

2.5. Lacq

The Lacq-Rousse pilot project was the first end-to-end industrial-chain CCS project. It was created and run by Total Exploration and Production France as one step in a broader strategy to reduce the company's environmental impact, especially with regard to GHG emissions. More specifically, the project was a way for Total to help develop the science and technology for CCS, gain operational experience and build public awareness and trust. It was based around existing assets near the town of Pau in southwest France. Gas produced from the Lacq field was processed and used to power (among many other things) an industrial boiler. That boiler was retrofitted with both oxy-combustion and carbon-capture equipment for this project. The captured CO_2 was then compressed and dried and piped 30 km to the depleted Rousse gas field, where it was injected and permanently stored. Total granted internal approval for the project at the end of 2006, kicking off design, construction, and permitting. Regulatory authorities granted operational permission in May 2009 under existing mining and environmental law. Injection began in January 2010 and ran for 39 months, until March 2013 (Total, 2015).

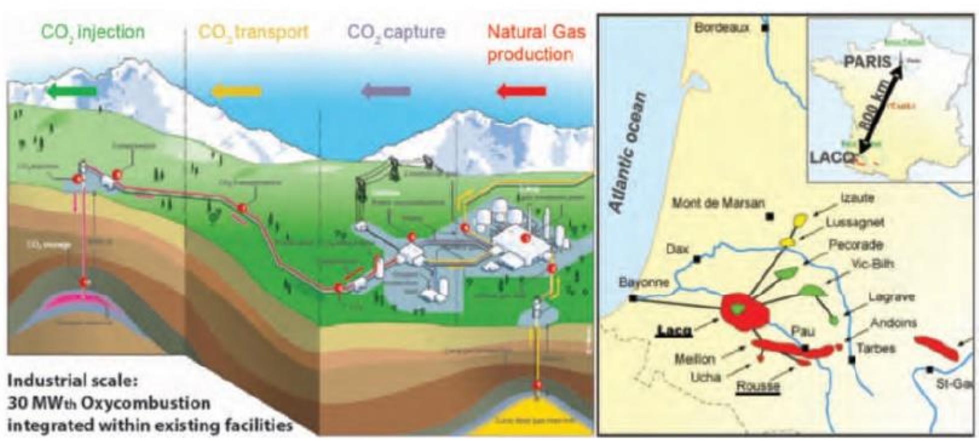


Figure 13: Lacq-Rousse project schematic and location map (Total, 2015).

In detail, the project had four key goals (Total, 2015):

- To show the technical feasibility and reliability of an integrated value chain from steam production to CO_2 capture, transportation, and sequestration in a depleted gas reservoir
- To gain operational experience with oxy-combustion and the data and insight needed to upscale it from pilot to commercial scale while reducing costs
- To develop methods and technologies for evaluating and monitoring geologic storage that could be applied to future large-scale projects

- To share broadly the knowledge gained, including scientific results, project achievements, and lessons learned

The Rousse gas field, the target of injection, was discovered in 1967 and contained 4.6% CO_2 and 0.8% H_2S at a pressure of 48.0 MPa (Pourtoy et al., 2013). Production began in 1972 with a single well, RSE-1, tapping two stacked reservoirs, the Mano and the deeper Meillon. The Meillon section of the well was plugged in 1985, upon influx of formation water. Production from the Mano continued until 2008, ultimately yielding ~32 Bcf from that reservoir and leaving final reservoir pressure at 4 MPa (Monne, 2012; Thibeau, 2013). Records of the original cement design and operations were no longer available by that time, so new logs were acquired to evaluate the integrity of the well and its potential response to injection. The new logs showed no corrosion of the casing and bridges of good cement around the entire wellbore, suggesting that it retained hydraulic isolation across the 836 m of cement set in the bottom section of the main seal interval. On the strength of those findings, the well was converted to an injector for CO_2 (Total, 2015).

Geologically, the Rousse structure is an isolated Jurassic horst block, 4 km^2 in area and draped with Cretaceous clays and turbidites (Figure 14). Three wells delineate the structure, but only one penetrates the Mano reservoir. The Mano is located at 4500 m depth and consists of dolomite mudstones, wackestones, and packstones deposited in tidal flat, peritidal, and barrier settings. Hydrothermal, collapse, and polygenetic breccias are also present. Polyphase diagenesis further complicates characterization. Matrix porosity is 2%–4% and effective gas permeability is 5 mD, based on regional well analysis. Stratigraphic thickness is 120 m (Monne, 2012; Thibeau, 2013; Total, 2015).

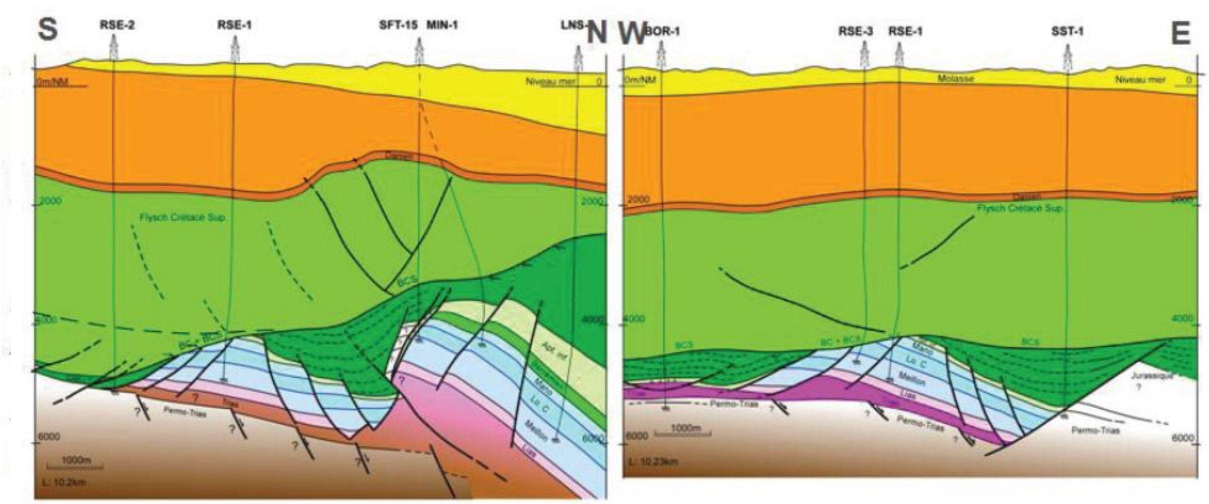


Figure 14: Cross sections showing the structure of the Rousse horst and location of the RSE-1 injection well (Total, 2015).

The structure is draped by Albian–Aptian clays that create an efficient lateral seal. These and the top of the horst block are truncated by the Base Upper Cretaceous Unconformity, which marks the bottom of the Upper Cretaceous “flysch” top seal (Figure 14). From that marker up to the lowest freshwater aquifer (in the basal Cenozoic deposits) are 2500 m of fine-grained sediments that act as the containment system. There is a thin breccia unit at the base, representing debris flows and containing clasts of the reservoir. This unit is not resolved on seismic and is not mappable. Kilometers of carbonaceous marine turbidites and calcareous marls overlie the breccia, and texturally similar material forms the matrix for the breccia. Laboratory measurements indicate a permeability of 0.1 nD and 1–10 nD in the turbidites and marls, respectively. The effectiveness of the seal is proven by the gas accumulation, and the bounding faults present no leakage risk as they are truncated by the unconformity (Pourtoy et al., 2013; Total, 2015).

Published reports of pre-injection characterization and modeling identified no serious technical risks. Geomechanical modeling indicated no mechanical damage to the seal caused by production and depletion and concluded that "the Rousse reservoir is ideal for CO_2 storage, with significant storage capacity…and little stress/deformation sensitivity to pressure changes…" (Pourtoy et al., 2013). Additional reservoir modeling concluded that the geochemical effects of injecting CO_2 were similar in magnitude to the more familiar effects of producing any acid gas, including the original accumulation at Rousse. The work also noted that density would cause the injected CO_2 to settle below the remaining gas, thereby further limiting the chance for any chemical alteration of the top seal. Interestingly, the authors also noted that gas production would have caused formation waters to vaporize near the wellbore, leaving no potential for new salt precipitation upon injection of CO_2 (Thibeau, 2013).

In preparation for injection, Total repurposed the existing gas pipeline, installed compression equipment at the Rousse wellsite, and added fiber optic cable to the well, with sensors for temperature, pressure, and microseismicity. Additional programs were organized to periodically monitor soil gases, groundwater quality, surface water quality, biodiversity, and atmospheric CO_2 concentration at the wellhead before, during, and after injection (Monne, 2012).

Injection began in January 2010 and lasted until March 2013, storing ~51 kt of CO_2 with no adverse events. No changes from baseline were detected in any of the water, surface and atmospheric monitoring campaigns. Downhole pressure and temperature measurements showed changes in line with the predictions of the reservoir model and post-injection pressure forecast to stabilize at 12 MPa, well below pre-production pressure. Importantly, pressure fall-off tests showed no changes in skin from the time of gas production and no changes in injectivity. Seismic monitoring picked up a number of naturally occurring events, but downhole sensors also detected hundreds of very small (less than magnitude 0) events, figure 15. These occurred close to the point of injection, their spatial distribution followed known fault trends and their timing was clearly injection related. They were far too small to cause any concerns about integrity but might offer a cost-effective means of tracking plume migration if future work could link them to the edge of the plume or the edge of the low-temperature zone (Monne, 2012; Prinet et al., 2013; Total, 2015).

Similar to the operators of other pilot and demonstration projects, Total made a significant effort to create an "'open' and 'transparent' dialog with all stakeholders upstream of the permitting process" (Total, 2015). Detailed information was made publicly available through a dedicated website, brochures, a

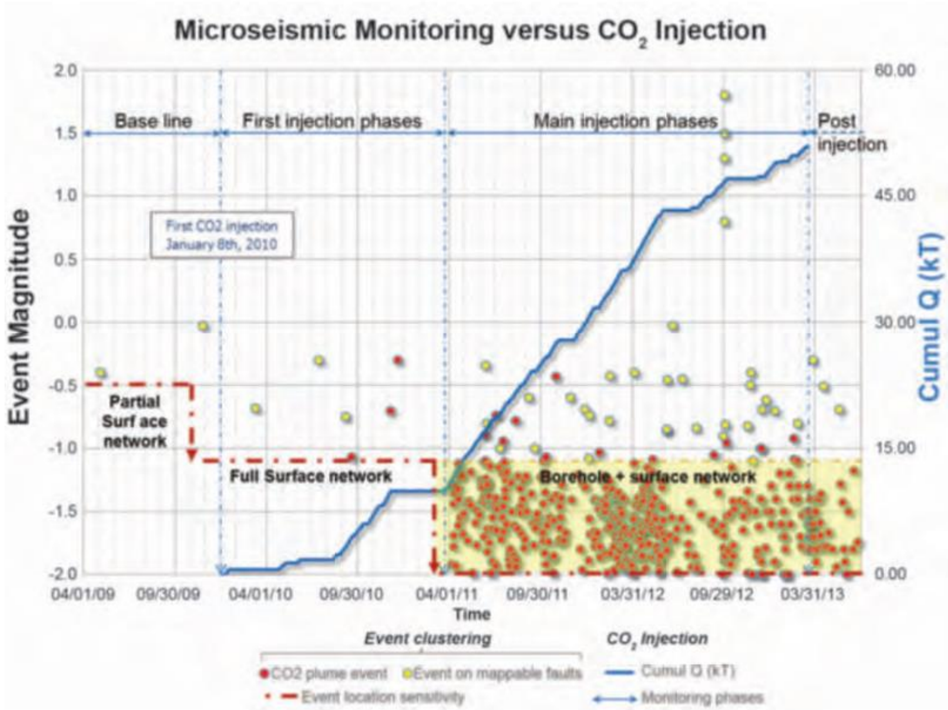


Figure 15: Microseismic events versus CO_2 injection (image resolution limited by the original publication; Total, 2015).

consultation dossier, a movie and quarterly newsletters mailed to local residents. Additionally, an early public consultation meeting in November 2007 led to the creation of a permanent local information and surveillance commission (CLIS) that included nine officials from local government, four state representatives, two trade union delegates, four representatives of associations, five experts, and four Total employees. This group met every six months, hearing reports, touring facilities, interviewing stakeholders, and maintaining their own independent website (Ha-Duong et al., 2010; Total, 2015).

Local residents of Lacq generally voiced no opinion or were in favor of the project, but the project faced significant opposition in Jurançon, near the site of the Rousse field. Although Total started from what was thought to be a position of strength as the dominant employer in the region and with decades of demonstrated safety, a local association formed in opposition to the project questioned Total's sincerity, questioned the independence of government experts, and questioned the role of CCS in climate change policies generally. As a result, the initial application to perform work at the wellsite was unanimously denied by the municipal council. Subsequent outreach reassured the mayor of the safety of the project and a deal was negotiated, requiring Total to set aside €1.5M for local community projects. Post-permitting analysis by outside academics offers useful insight (Ha-Duong et al., 2010):

> *'In this case, Total demonstrated a strong will to engage a concertation, allocating significant resources early on: hiring a consulting firm and allocating senior engineers' time to answer the questions. The concertation covered the whole territory from Lacq, where acceptability was likely from the start, to Jurançon where things were more delicate. The social conditions were very favorable to the project. For two generations, the operator has been the first economic and therefore political power in the area, and has consistently demonstrated that it could control higher risks. The project answered local needs for economic development directly and indirectly,*

in the long run context of the gas-field depletion. Research on CCS is supported nationally and internationally by scientists and States. All these reasons contribute to explain why the permit was obtained.

Still there are lessons to be learned. Total's position would have been stronger if its permit request had been expertized by a different team and if it had more-specific long-term plans. Because concertation meetings were held before elections, the local officials could only take a noncommitted stance. Using a Parisian consulting firm to moderate the discussion, and employing hostesses to hand out the information packages was not appreciated by the people of Jurançon. Total, following the advice of the president of the National Commission on Public Debates, did not mass-mail the community with information on the project. Consequently, citizens came to the meetings to receive information, not to defend a stance in a debate. Another reason why the public participation in the discussion was low is that smaller formats might have been more interactive.'

2.6. Otway

Around half of Australia's yearly GHG emissions come from point sources, largely power-generating facilities, that could be amenable to CCS (Sharma et al., 2011). The CO_2CRC Otway project was conceived as Australia's first onshore CCS project, a non-commercial opportunity to confirm and extend the science, develop local technical capacity, and build public familiarity and trust. The project developers began searching for a site in 2004 and settled on two adjacent fields in a mature hydrocarbon province in the Otway Basin in Victoria state, Australia (Figure 16) (Jenkins et al., 2012).

The Buttress field was discovered in 2002, but with 75.4 mol% CO_2 and only 20.5 mol% methane, the discovery well was cased and suspended without being perforated or produced (Sharma et al., 2011; Underschultz et al., 2011). Two kilometers to the south was the Naylor field, a small gas accumulation with ~6 Bcf GIIP (gas initially in place). Between February 2002 and October 2003, it produced 3.3 Bcf from the Warre-C reservoir through a single well, recovering about 64% of the gas in place in that reservoir. Increasing water cut led the operators to patch the perforations and recomplete the well in the deeper Warre-A interval, where it produced for another 8 months until water incursion again forced shut-in. The first preparations for CO_2 injection began in 2004 with characterization studies on existing data, followed by targeted data acquisition programs in parallel with permitting negotiations and public outreach (Sharma et al., 2009; Underschultz et al., 2011; Dance, 2013).

The primary reservoir at Naylor was the Cretaceous Warre-C formation at 1980–2180 m true vertical depth sub-sea (TVDSS). It is described as a poorly sorted very fine to coarse quartz sand with irregular gravels 2-14 m thick. Thin mudstones 0.5–13 m thick create local flow barriers, and the entire reservoir unit is 25–40 m thick. Depositionally, it is interpreted as a braided fluvial deposit with increasing marine influence. Porosity ranges from 10%–28%, with an average of 17%. Average permeability is 2700 mD. Containment is provided by multiple layers. Immediately above the reservoir is the Flaxmans Formation, which fines upward into bioturbated mud. Overlying that is the primary seal, the black marine Belfast mudstone, with less than 1 mD permeability and averaging 280 m thick. In turn, the Belfast is capped by the Skull Creek Formation, a carbonaceous mudstone with interfingering siltstones and minor sandstones.

The Belfast is a proven regional seal, known to retain hydrocarbons across the Otway Basin (Underschultz et al., 2011; Dance, 2013).

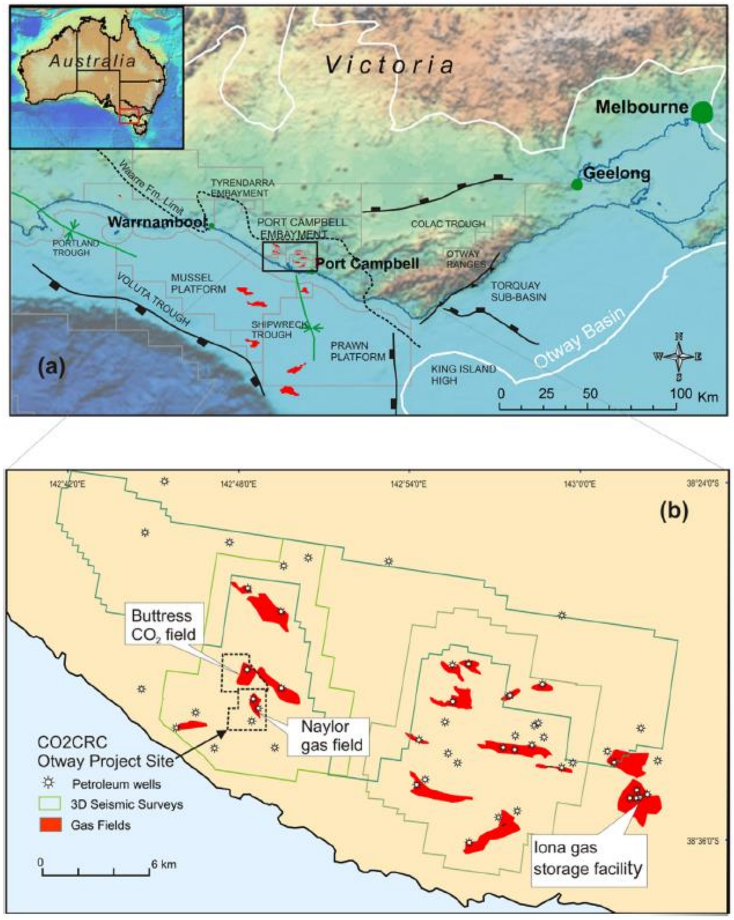


Figure 16: Location of the Buttress and Naylor fields (Dance, 2013).

The Naylor trap is a tilted fault block, bounded on three sides by sealing faults and on the fourth by a gentle eastward dip (Figure 17). These faults were deemed low risk for leakage because (A) they had proven capable of trapping buoyant hydrocarbons over geologic timescales and (B) they die out upward within the Belfast mudstone without breaching the top of it and without seismic evidence of gas chimneys (Dance, 2013).

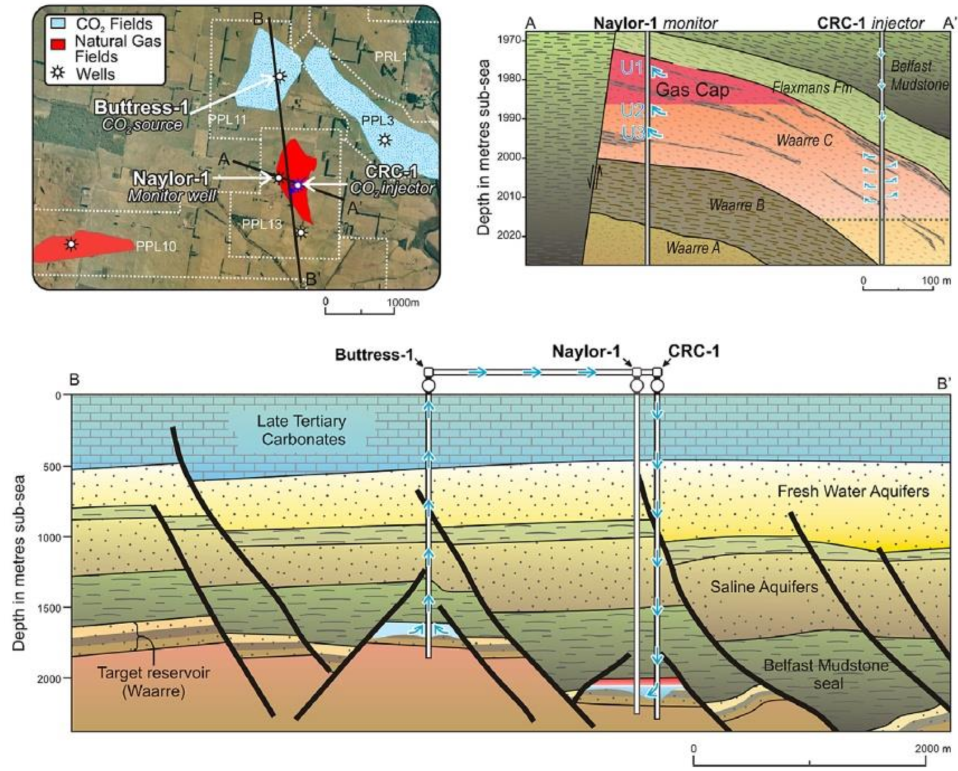


Figure 17: (A) Detail of the Naylor field showing the Warre-C reservoir interval, the post-production gas cap and the position of the two wells. Dotted line indicates the pre-production gas–water contact. (B) Regional cross section showing both the Naylor and Buttress fields (Dance, 2013).

At the time of discovery, reservoir pressure at Naylor measured 19.6 MPa at 2015 m TVDSS in the water leg. By the end of production in October 2003, that had declined to 11.0 MPa, indicating a limited aquifer connection. History-matched reservoir models forecasted a limited rebound, but by the time the injector was drilled and logged in June 2006, pressure had recovered to 17.4 MPa, well in excess of predictions. Reconditioning the reservoir model with a more extensive dual-aquifer system in pressure communication with neighboring fields allowed the team to honor the new observations. The reconditioned reservoir model predicted a field storage capacity of 150 kt, well in excess of the planned 100 kt injection and comfortably shy of the amount of gas already produced (equivalent to 220 kt CO_2 at reservoir conditions). Injected CO_2 was forecast to take 4–8 months to migrate from the injector to the monitoring well 300 m away, with pressures peaking below pre-production values. A quantitative risk assessment estimated that the likely leakage rate was below 0.001% per year, in line with international standards (Underschultz et al., 2011; Jenkins et al., 2012).

Injection began in March 2008 using CO_2-rich gas taken from the Buttress field and transported 2.25 km to Naylor though a purpose-built pipeline (Figure 17). Three U-tube sampling ports in the Naylor-1 monitoring well allowed the operators to collect pressurized fluid samples and to track the movement of the gas–water contact. Tracers were added to the injected CO_2 to facilitate clear identification upon arrival at the monitoring well and 3D seismic surveys were acquired pre-, syn-, and post-injection, also helping to track fluid movement. Regular sampling of groundwater, soil gas, and air completed the monitoring program. Injection ceased in August 2009, by which time the project had stored 65 kt and met all of its key objectives (Sharma et al., 2011; Jenkins et al., 2012). Detailed project learnings fill a book (Cook, 2014), but the major outcomes can be summarized as follows:

1. Groundwater and soil gas sampling found no anomalies. Atmospheric sampling was complicated by large diurnal and seasonal changes, however it proved sufficiently sensitive to pick up the local CO_2 increase created by the diesel engines powering the drill rig, an interpretation confirmed by tracers. None of these saw any sign of injected CO_2 leaking from the reservoir. Experiments with modeling hypothetical subsurface leaks showed that the 4D seismic surveys would be capable of detecting leaks on the order of a few kilotons/year if there were a discrete pathway from the reservoir, for example, via a leaking fault. No leakage was actually detected but the detection sensitivity demonstrated would be sufficient to pick up leakage of 0.1% or less from industrial-scale injection projects (Jenkins et al., 2012).
2. The use of chemical and isotopic tracers in the injected CO_2 plus the ability to monitor reservoir fluids at three different depths, allowed researchers to track the movement of the gas–water contact and determine the storage efficiency of injected CO_2 as it refilled the reservoir. Although hampered by uncertainties in the residual CH_4 saturation, the range of movement of the CO_2 and the pore volume itself, careful calculations suggested that 56%–84% of the pore space originally filled with hydrocarbons was re-occupied by injected CO_2. That is in line with experience in natural gas storage and with the common figure of 75% used in global capacity estimates for depleted fields (Jenkins et al., 2012).

Perhaps the most significant project outcome was not technical but legal. At the start of the project, Australia had no regulatory regime for CCS. All of the project's permitting, regulation, and long-term liability had to be negotiated in the course of the project. Starting with existing petroleum law, the operators worked with Australian state and national governments to identify and work out the overlaps, contradictions and gaps between multiple jurisdictions. Ultimately, permitting took over two years and required "innovative solutions and unprecedented cooperation between project participants, government bodies and the community" (Sharma et al., 2009). Getting and keeping the consent of local stakeholders was especially important. The project leaders created a communications strategy based on market research and proactively reached out through printed materials, press releases and a comprehensive website. "Key principles were a willingness to listen to the public, to be open about all aspects of the project, and to ensure no surprises—any news about the project was communicated first by the CO_2CRC directly to those affected" (Jenkins et al., 2012).

2.7. Cranfield

In the mid-2000s, the US Department of Energy's Regional Carbon Sequestration Partnerships (RCSP) program, led by the National Energy Technology Laboratory (NETL), was looking for field opportunities for carbon sequestration research and monitoring. Specifically, the relevant program goals were to "… develop technologies that will support industries' ability to predict CO_2 storage capacity in geologic formations …" and "develop technologies to demonstrate that … injected CO_2 remains in the injection zones" (Hovorka et al., 2013). The SECARB regional partnership decided that one of its field projects would focus on a CO_2-EOR flood with a large aquifer, a vehicle to research monitoring and the concept of stacked storage. After broad review, Cranfield was chosen from among 767 fields screened (Hovorka et al., 2013).

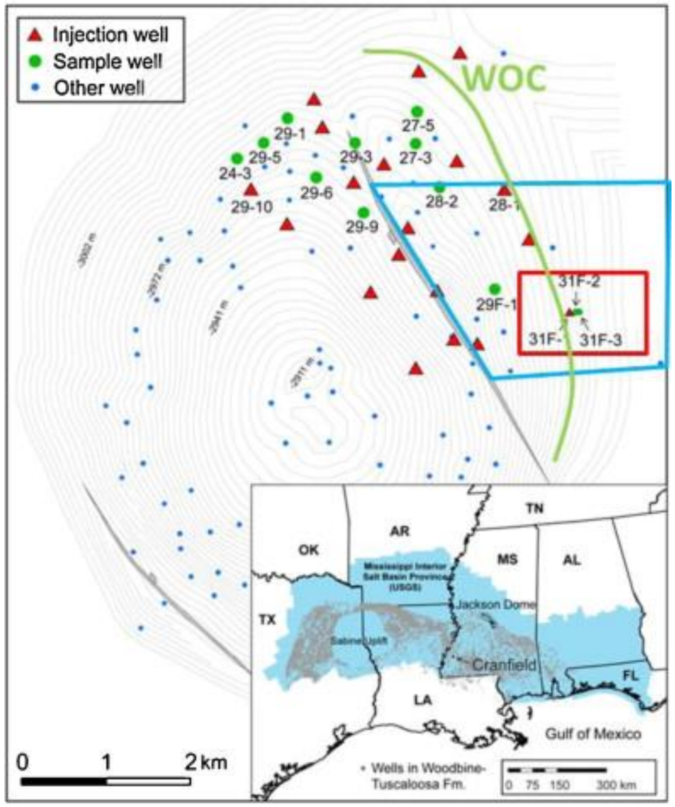


Figure 18: Map of the Cranfield field, showing depth contours on the top of the reservoir, the two faults, and the locations of wells (Hosseini et al., 2013).

Cranfield is an oil and gas field located in southwestern Mississippi (Figure 18). It is a four-way anticline with a shallow crestal graben. The main reservoir is the basal conglomerates and sandstones of the Cretaceous Tuscaloosa Formation at a depth of ~3000 m (Figure 19, overleaf). These are fluvial-deltaic deposits interpreted to have been laid down in a semi-arid climate. The reservoir interval, informally known as the "D-E" sands, is 20–28 m thick, sandwiched between red terrestrial mudstones at the top and Washita-Fredericksburg Group mudstones at the base. The reservoir itself is a complex system of incised channels filled with lithic-rich sands and conglomerates, occasional muds, and thin intra-formational shales. Variable concentrations of chlorite, quartzite, and carbonate cements add to the complexity of the flow unit (Hovorka et al., 2013). Porosity is in the range of 20%–25% and permeability averages 10–200 mD (Hosseini et al., 2013).

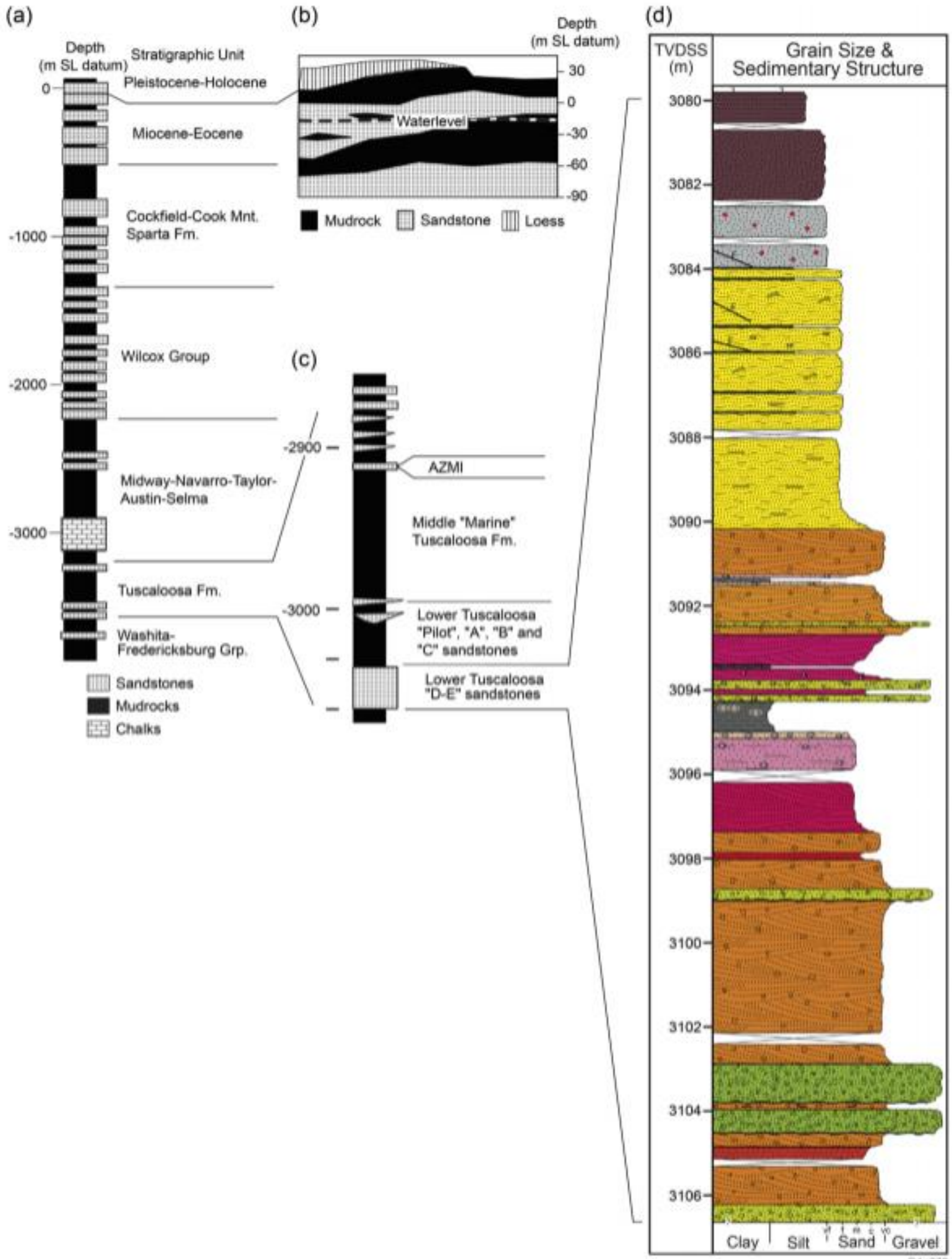


Figure 19: Lithostatic Column: (a) Generalized stratigraphic section. (b) Near-surface stratigraphy. (c) Detail of Tuscaloosa Formation from wireline logs. (d) Core facies interpretation (Hovorka et al, 2013).

The reservoir is sealed on the bottom by low-permeability mudstones and on the top by mudstones and fine-grained, calcite-cemented sandstones of the middle “marine” Tuscaloosa Formation. Above that is a thick sequence of alternating permeable sandstones and low-permeability fine-grained units, the thickest of which is the Midway shale, ~900 m above the reservoir. In combination, these layers create a formidable containment system for vertically migrating fluids (Hovorka et al., 2013).

The anticline is cut by two northwest–southeast-trending faults (Figure 18). The northeastern of these bounds the injection area and has a throw of ~25 m, roughly equal to the reservoir thickness. The fault is not active, nor does it breach the Midway shale. Fluid contacts were different on either side of the fault at the time of discovery, and subsequent CO_2 injection on one side showed no pressure impact on the other side. Moreover, the present-day maximum compressive horizontal stress is oriented perpendicular to the fault, tending to close it. For all of these reasons, the fault is not thought to be transmissive, either horizontally or vertically (Nicot et al., 2013).

The field was discovered in 1943 by the California Company (now Chevron). Oil production from the primary reservoir, the Cretaceous Lower Tuscaloosa, began in 1944, initially recycling the gas for pressure support. As oil production rates waned, focus shifted to blowing down the gas cap, beginning in 1959. The primary reservoir was abandoned in 1966, having produced ~37 mmbbl of oil and ~672 Bcf of gas. Minor production continued from a shallower reservoir, the Eocene Wilcox, but the Lower Tuscaloosa remained shut in for decades. In the mid-2000s, Denbury Onshore LLC acquired the field for redevelopment using CO_2-EOR (Nicot et al., 2013). At the same time, the SECARB regional partnership was looking for a CO_2-EOR field to use as a vehicle for its research program. Key criteria were a willing operator, a site amenable to project objectives in testing monitoring techniques, cost of preparation, cost and availability of CO_2, and last, a holder of CO_2 liability. Not only did Cranfield fit those criteria but it avoided many of the complexities common in CO_2-EOR fields. Instead of EOR operations beginning at the end of secondary production, with a highly uneven pressure and fluid distribution, the long dormant period between the end of production in 1966 and the start of EOR in 2008 had allowed the reservoir to recover to near-virgin pressure. Additionally, Denbury’s operating plan called for continuous injection of CO_2, rather than water-alternating-gas (WAG), which is commonly used in the region (Hovorka et al., 2013).

In preparation for CO_2 injection, the operator shot a new 3D seismic survey and drilled 29 new wells (as of 2012) with comprehensive data acquisition programs including modern log suites as well as core and fluid sampling. An existing gas pipeline was repurposed to carry CO_2 from a naturally occurring accumulation at Jackson Dome to Cranfield. Injection began in June 2008, ramping up in steps to 1 Mtpa in April 2010 and storing a total of 5.37 Mt over the course of the study, between April 2010 and January 2015 (Hovorka et al., 2013; Alfi and Hosseini, 2016). In keeping with the project objectives, the active injection area was monitored, with much of the monitoring heavily focused on one three-well area, to test an array of methods to assure CO_2 containment and enhance future capacity predictions. Key learnings are as follows:

1. Pressure monitoring is a common practice in oil field surveillance, and there was significant interest in its application to CO_2 injection. At Cranfield, pressure monitors were installed at the wellhead, in the reservoir, and also in a shallower sandstone (the “above zone monitoring interval” [AZMI]). These provided valuable calibration points for geocellular fluid flow modeling

(Hosseini et al., 2013). Modeling is often non-unique in the best of cases, but given the high degree of reservoir heterogeneity at Cranfield, the uncertainties in interpreting reservoir boundaries could have easily masked leakage signals (Figure 20, next page). Injection well start-up created clear pressure signals as much as 3 km away, giving valuable insight on reservoir connectivity. However, 29 new producers were brought onstream during the course of the project, analogous to creating 29 leaks in the reservoir since the wells were driven only by natural lift. These created no pressure signal distinct from background noise, casting doubt on the ability of pressure monitoring to detect leaks (Hovorka et al., 2013).

2. As of 2012, there were 287 known wells in the field, including over 170 penetrations of the Tuscaloosa reservoir. Most of these were drilled in the 1950s and 1960s. With multiple thick mudstone seals and no fault conduits breaching the entire confining system, these wells represented the primary containment risk. Nicot et al. (2013) analyzed cement bond logs (CBLs) from a sample of 14 wells drilled between 1960 and 2010. Of these wells, all but one had intervals of questionable cement bond, according to established evaluation standards. Two of these were considered of highest concern, as both lacked an adequate section of good cement across the confining interval (middle Tuscaloosa). However, analysis of average permeability over the entire length of the wellbore showed that even small sections of good cement were enough to reduce the average permeability by 5 to 7 orders of magnitude versus wells with only questionable cement. A simple 1D model developed to assess leakage potential showed that pressure-driven upward flow would be quickly attenuated in the multiple permeable zones above the reservoir. Buoyancy-driven CO_2 flow could conceivably continue upward, but analysis of a further 17 wells indicated that at most two (and possibly none) would be capable of transmitting a total of 1.8 tons of CO_2 per year to shallow freshwater aquifers or the surface. At most, that represents 0.0002% of the CO_2 injection rate (Nicot et al., 2013).
3. In the interests of improving future capacity assessments and finding optimal relationships between CO_2 storage and increased oil production, a comprehensive reservoir model was built. The model was history matched with pressure trends, hydrocarbon production, CO_2 injection, 4D seismic observations of plume spread, and breakthrough times observed in production wells. The tuned model was then used to explore the ultimate storage capacity of the field under different operational scenarios. With CO_2-EOR including recycle of CO_2 conducted for the entire modeling period, the field was predicted to be able to store 24.1 Mt. With CO_2-EOR conducted for the EOR profitable period followed by a period of pure storage, the field stored 9% less, or 22.2 Mt. The study suggested replacing continuous CO_2 injection with WAG to achieve higher sweep and storage efficiency (Alfi and Hosseini, 2016).
4. 4D seismic was acquired but proved to be of limited use in tracking plume edges. The difficulty was partly due to the fact that the reservoir is deep and partly due to the fact that the presence of residual methane and oil in the reservoir limits the acoustic-impedance contrast with CO_2. A novel tool shown to be effective for plume tracking was cross-well electrical resistance tomography, which measures electrical resistance between pairs of electrodes. Automated surveys were run multiple times per day, giving high-resolution updates on changes in resistivity that were plausibly linked to CO_2 movement. Joint inversion with other datasets may yield further insight. The most difficult part was installation of the sensors, which required a non-conductive environment, sufficient armor to operate at 3200 m depth and mitigation of possible CO_2 leakage pathways through the cabling or cement (Doetsch et al., 2013).
5. It was determined that the main value of monitoring for CO_2 leaks above surface was safeguarding against incidents and allegations. Above-zone pressure monitoring was found to be the most effective leak detection technique. Process-based methods were developed to improve the ability

to separate leakage signal from background. Groundwater surveys were statistically unlikely to detect any leaks (Hovorka et al., 2013).

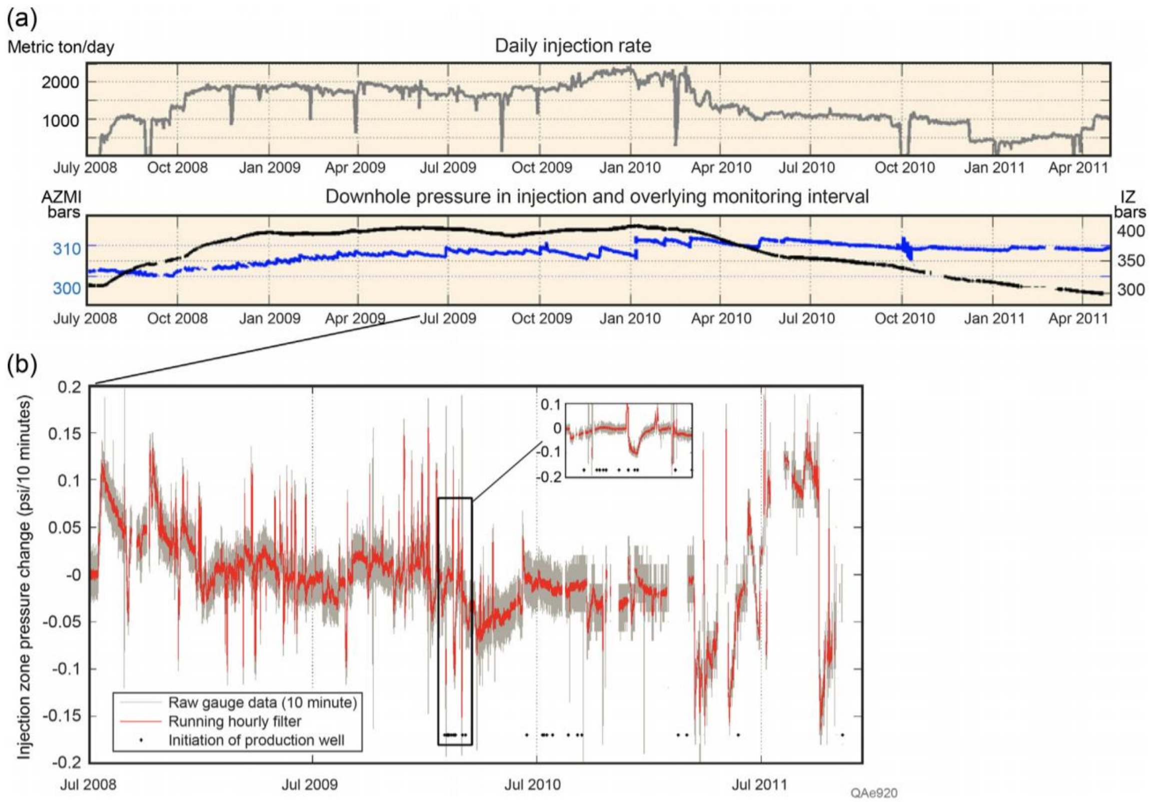


Figure 20: (A) Daily injection rate and bottom-hole pressure (black). (B) Rate of Change of pressure with timing of initiation of production for 13 wells started during the time frame shown as dots (Hovorka et al 2013).

2.8. Weyburn and Midale fields

After discovery in 1953, primary production, waterflood, and infill and horizonal drilling, production from Weyburn oil field began again to decline (Figure 21). To offset this decline, a new commercial CO_2-EOR project was developed in 2000, initially in patterns, in the Weyburn field. The CO_2 source was captured CO_2 from Basin Electric Power Cooperative Dakota Gasification Company's Great Plains Synfuels project (Dakota Gasification Company, 2021). CO_2 was transported from Beulah, North Dakota, USA, via a dedicated 330-km, new-built pipeline. Initially the pipeline carried 5000 tons per day of CO_2 at 2600–2700 psi. The commercial project has continued to evolve, including an increased number of patterns in Weyburn field and expansion into adjacent and geologically similar Midale field, increasing the amount of CO_2 transported to 7500 tons per day, and transitioning to using CO_2 captured from SaskPower's Boundary Dam capture project in 2014 (Brown et al., 2017; SaskPower, 2021). The operators of the commercial flood had a high impact on CCS studies of depleted fields because they hosted an extensive multi-phase early R&D project (IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project and follow-on research) (Figure 22). The research and development elements have been extensively documented in reports and peer reviewed publications. However, some operational aspects of the commercial project are not readily available in the peer-reviewed literature.

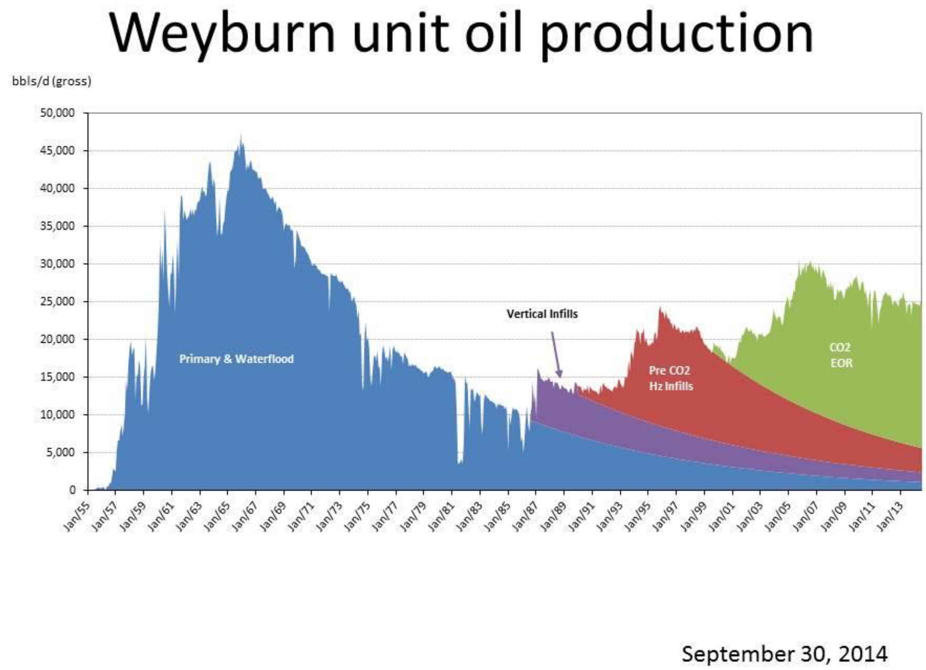


Figure 21: Weyburn production history showing a typical evolution of investment in a depleting field. From PTRC (https://ptrc.ca/projects/past-projects/weyburn-midale#images-4).

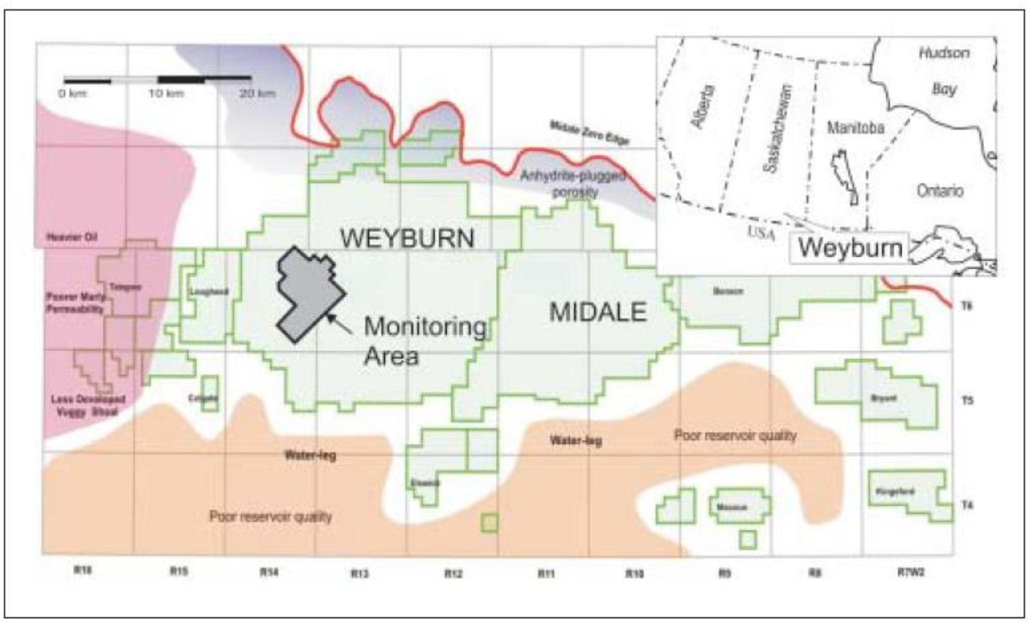


Figure 22: Location of Weyburn and Midale fields and the IEAGHG Monitoring and Storage Project monitoring area. From (White, 2008).

The geologic setting is somewhat unique in that the Weyburn and Midale reservoirs are formed by an angular unconformity that truncates the Mississippian-age Midale dolomitic reservoir units by angular unconformity, overlain by Triassic mudstones of the Watrous Formation. Understanding the Midale reservoir facies and diagenesis has been extensively studied and reported which includes grainstone and packstone bar facies and finer-grained interbar, tidal flat, and lagoon facies with overprints of dolomitization and variable anhydrite cementation. Designing the CO_2 sweep to access both the lower "vuggy" and upper "marly" zones has been important in designing the CO_2 flood. A regional fracture system was identified and then illuminated during 4D systemic imaging of the areas swept by CO_2.

The Weyburn history of infrastructure investment to offset depletion has been well documented (Brown et al., 2017). Many fields have had an overall similar evolution, but individual decisions made in response to the reservoir properties or innovations add unique aspects to each one. As is typical, in Weyburn, an initial phase of primary production starting in 1957 was followed by a need to pool the production and maintain pressure by reinjecting produced brine and other fluids to create a water flood, leading to peak production in 1967 (Figure 21). Steady decline in production was offset in 1985 when a program of first vertical then horizontal infill wells was started. A CO_2 pilot designed by Shell using trucked-in liquid CO_2 regassified prior to injection was run at Midale field during 1984–1989 (Brown et al., 2017). Transfer of this experience at full scale to Weyburn, then operated by PanCanadian, required identification of the CO_2 supply, and a number of options were considered before selection of the Dakota gasification plant, as documented in detail by Brown et al. (2017).

For the CO_2 flood, in addition to reuse of vertical wells, on the order of 100 additional horizontal wells were drilled to flood the thin and heterogeneous marly unit above the shoal facies of the vuggy unit because it had been previously poorly swept (S. Whittaker, 2020, written communication) (Figure 23). The fracture system was also considered in the CO_2 flood design.

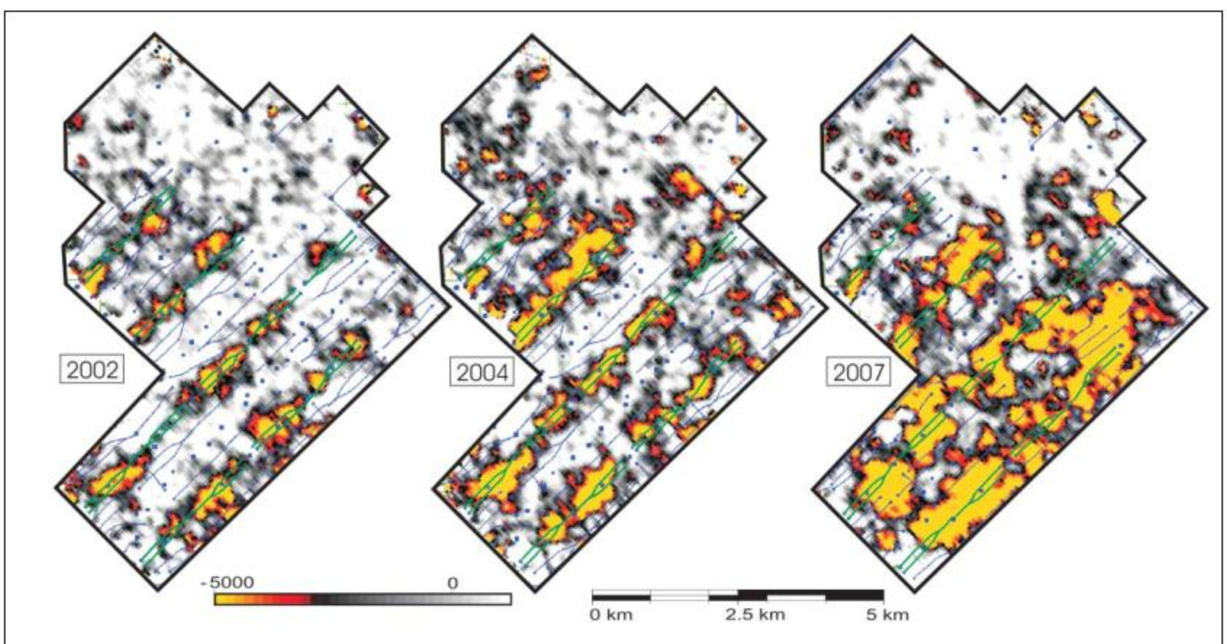


Figure 23: Time-lapse amplitude change for the middle marly horizon showing negative amplitude changes associated with CO_2 displacing brine along horizonal injection wells shown in in green (White, 2009).

The Weyburn case illustrates that depletion is a relative term. The production history shows strong depletion of resource available by one method, but then redevelopment using a new approach has brought the field back to production at a significant fraction of maximum.

Weyburn has had a varied pressure history, starting with 15,000 kPa initial pressure followed by a sharp decline during initial production with pressure elevation during water flood. EOR flood has generally returned pressure back toward but slightly above initial pressure (Figure 24).

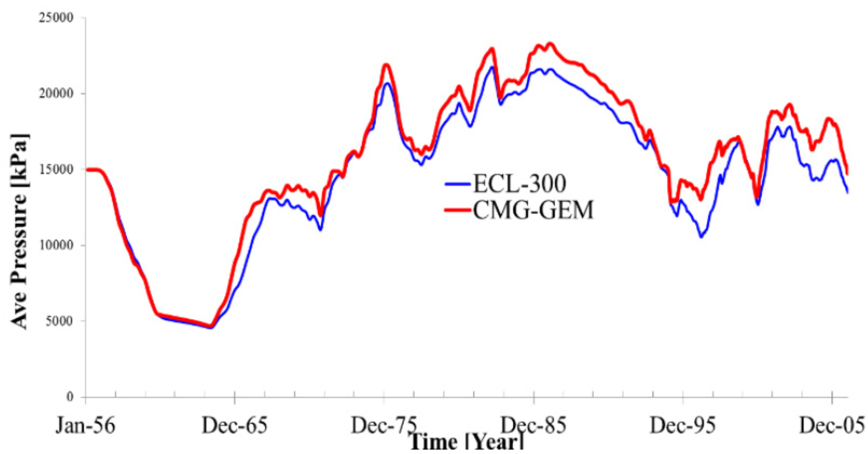


Figure 24: Modeled pressure in Weyburn field (Nicot et al., 2017).

Multiple risk assessment efforts conducted by various teams using different methodologies as part of the IEAGHG Weyburn project have consistently determined that the major risk to storage permanence is possible failure of wells to isolate the injection zone from shallower zones, regional aquifers, or the surface. Well construction has varied over the evolution of the project. The horizontal legs of wells are uncased, and the completion practices have varied over time. The most significant variable is the emplacement and quality of cement in the rock-casing annulus of the curving "build section" where the upper vertical parts of wells are deviated to become horizontal. In Weyburn the build section of wells typically lies within the Watrous Formation seal. It can be difficult to install a continuous cement sheath in a curving wellbore and casing. However, after intense study, no leakage events have been reported. Understanding and developing best practices for managing well failure risks was a recent project element that received a state-of-the-art analysis that generally validated the usefulness of commercial tools for assessing wells (Sacuta et al., 2015). Cementing, debonding between casings and the wall rock, and channeling in the cement are possible containment risks (Wildgust et al., 2013). A study of a 1957 well exposed to CO_2 was undertaken to develop recommendations for assuring well integrity in new well construction as well as remediating and converting existing wells (Hawkes and Gardner, 2013). In repeat 3D seismic surveys, a velocity change above the reservoir was tentatively interpreted as out-of-zone migration of CO_2 along wells that possibly did not isolate the reservoir from immediately overlying zones (Don White, CMC, oral presentation at IEAGHG Monitoring Network meeting, 2015) However, there was no evidence of vertical migration. The possible CO_2 anomalies remained beneath multiple additional confining zones.

A widely published incident occurred in which a property owner and their consultants claimed that CO_2 had leaked from the Weyburn reservoir to surface. However, a multidisciplinary study of the geochemistry of the soil gas and groundwater gases in the alleged leakage area showed that no detectable leakage had occurred (Romanak et al., 2013; Sandau et al., 2019). This false alarm provides a useful cautionary tale to be considered about how to protect the reputation of future projects.

An interesting case of leakage detection was reported during start-up of the Weyburn CO_2 injection. The CO_2 supplied from the Dakota gasification process contains trace amounts of the additive mercaptan, which makes natural gas detectable by humans by odor at low concentrations. The mercaptan smell led the operator to tighten fittings on CO_2-handling equipment to eliminate small leakage points and the smell was eliminated.

2.9. SACROC (Kelly Snyder field)

The earliest and longest-running commercial CO_2-EOR operation, known as Scurry Area Canyon Reef Operators Committee (SACROC) is operated by Kinder Morgan at the Snyder-Kelly field in Scurry County, West Texas (Figure 25). Limited public data are available about the overall operation; however, a subset of the field was a study area for a DOE-funded Phase III study as part of the activities of the Southwest Regional Carbon Sequestration Partnership which led to fairly extensive publications about the reservoir and near-surface response to CO_2 injection (e.g., Yang et al., 2014)

The Kelly Snyder field is formed in a topographic high on the Horseshoe Atoll, an aggregational positive feature developed in the slowly subsiding northern part of Midland Basin (Figure 25 and Figure 26). Highly cyclic facies include slope crinoid rudstone, shelf-margin phylloid algal boundstones, and shelfal packstones, wackystones and grainstones with crinoids, skeletal material, phyloid algae, fusulinids, and ooid grains in carbonate mudstones (Alnazghah, 2018). Exposure during low stands resulted in formation of vuggy porosity and other karstic features (Isdiken, 2013). The reservoir is limestone and the vertical and lateral variability, complex pore structure as well as thickness of the oil column were considered in the design of the CO_2 flood.

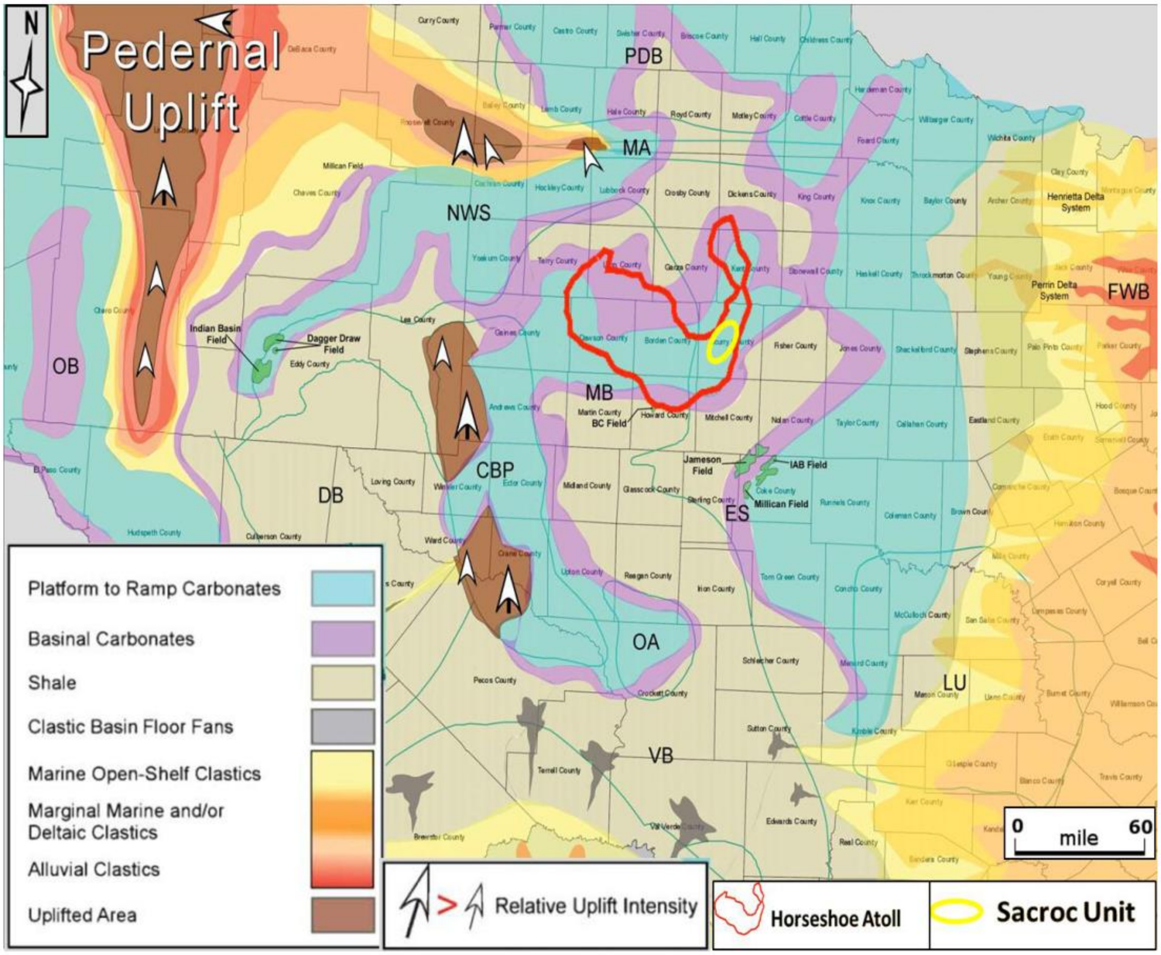


Figure 25: Location of the Kelly-Snyder Field as part of the greater Horseshoe Atoll trend (from Isdiken, 2013).

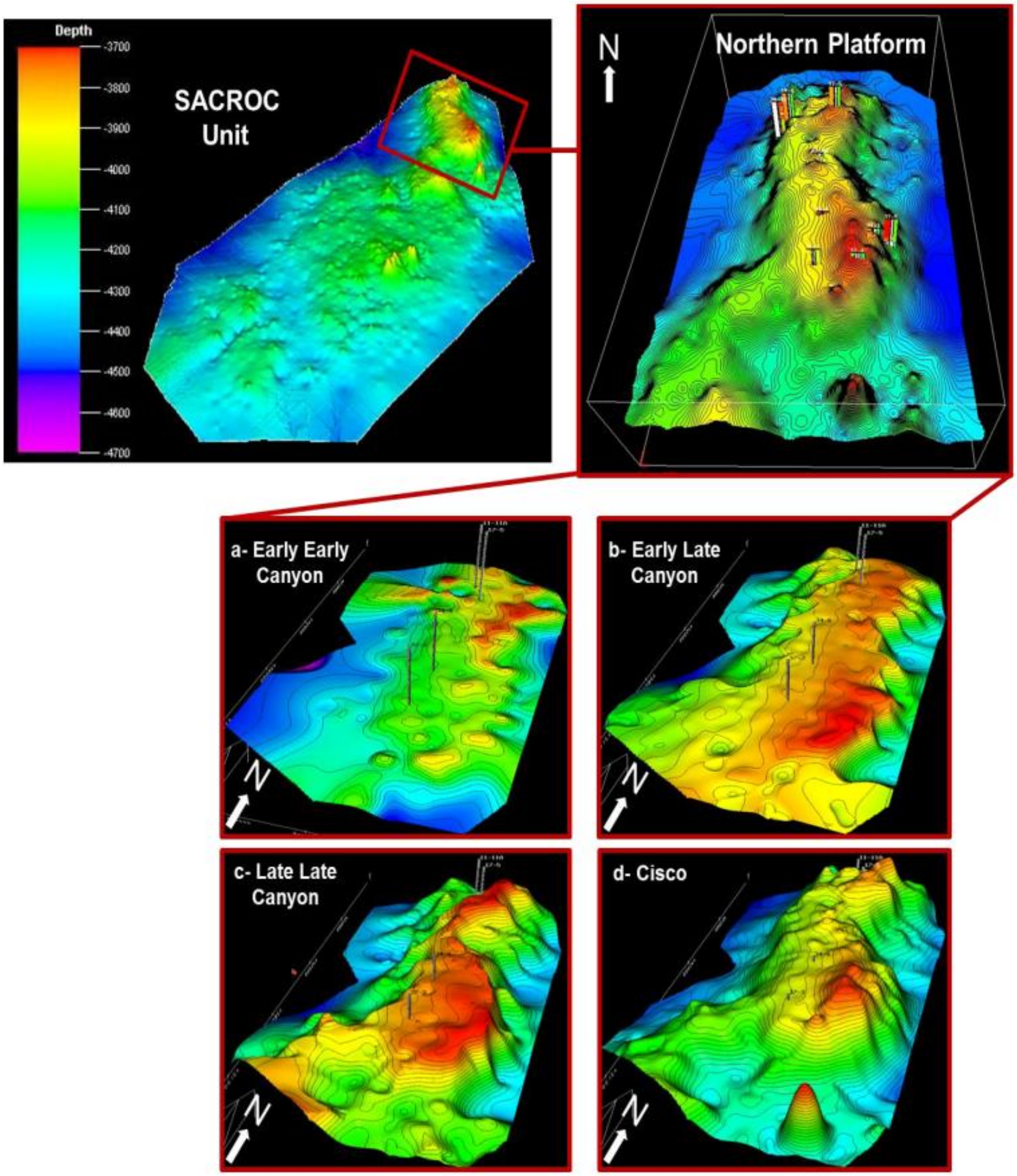


Figure 26: Structure on top of various horizons in the SACROC areas (from Isdiken, 2013).

The Kelly and Snyder fields were discovered in 1948 and put into production rapidly, so that by 1951, 1617 wells had been drilled by 88 operators. The field produces by solution gas drive with minimal water drive. Formation of the operators committee SACROC in 1951 was needed in response to pressure drop resulting from fast production to manage the pressure, which they did initially via water injection (Figure 27). Pilot testing of CO_2-EOR in 1968 was favorable, and was expanded in 1972 to 202 patterns. In 2000, Kinder

Morgan bought SACROC, and under their operation CO_2 EOR continued to expand to include about 500 injector-producer patterns (Galloway et al., 1983; Smith, 2021)

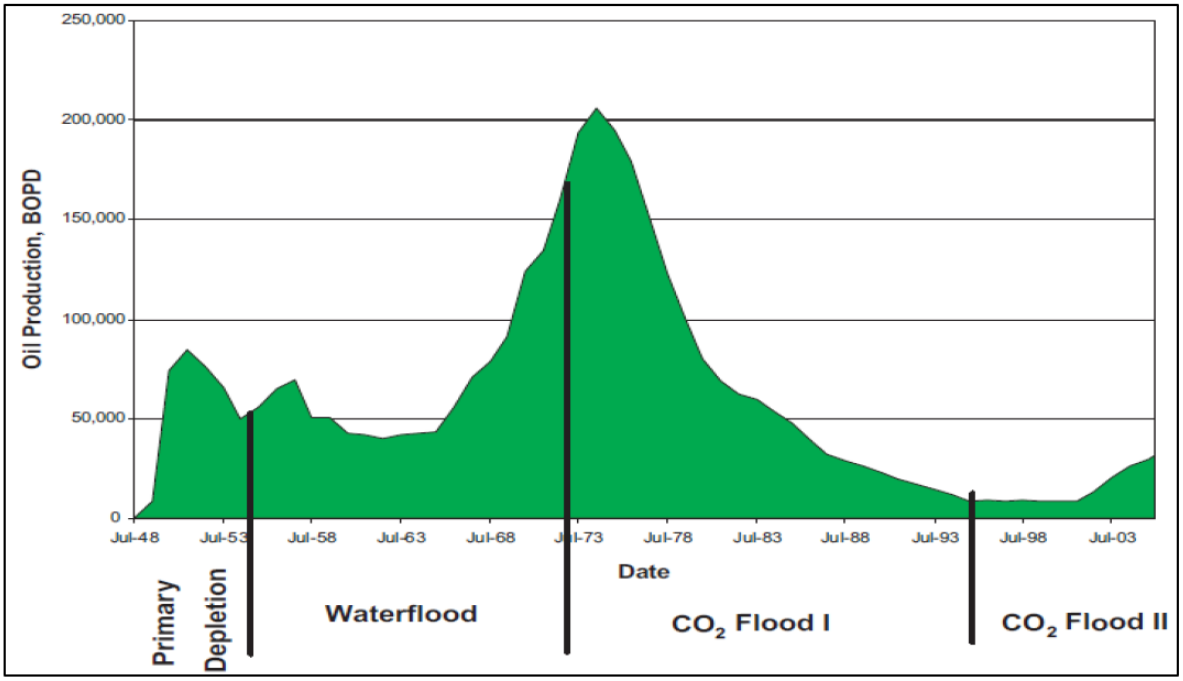


Figure 27: Oil production history of SACROC field (Idiken, 2013).

This field is a useful case study for depleted fields because of its long operational history. There are no peer reviewed reports on operations, however a review of the various types of normal field management processes required is possible. The field is managed to be compliant with the US Underground Injection Control (UIC) Program as implemented by the Texas oil and gas regulation agency, the Railroad Commission (RRC) under Class II permits (RRC, 2021a). Class II permits require many of the same parameters as needed for storage-only project, such as requirements to demonstrate a sufficient thickness of relatively impermeable strata that isolate injectate from useable water resource, cement jobs that assure isolation of injectate from freshwater both in the permitted injection well and in wells in an area of review around it. Wells are required to have a double walled system with tubing and packer inside of the casing, and to monitor and report pressure in each annulus, and report any problem within 24 hours. The operator implements a program to conduct Mechanical Integrity Tests (MIT) prior to injection, following any workover, and at 5-year intervals to test for leaks in the tubing, casing or packer. Wells are required to be plugged following specified procedures at the end of its use. A review of the data base of well problems and blowouts maintained by RRC illustrates the types of problems encountered at SACROC (Table 2, overleaf) as part of this case study.

Date	Operator	Unit	Field	County	Fire	H2S	Injuries	Deaths	Remarks
11/05/2012	Kinder Morgan Production Co. LLC	SACROC Unit	Kelly-Snyder	Scurry	N	Y	0	0	During plugging operations well started blowing out through the tubing when the tubing was approximately 10 ft. in the air
9/22/2010	Kinder Morgan Production Co. LLC	SACROC Unit	Kelly Snyder	Scurry	N	N	0	0	Hole in the surface casing. (Well was being used as a disposal well.)
6/11/2009	Kinder Morgan Production Co LLC	SACROC Unit	Kelly-Snyder	Scurry	N	Y	0	0	5-6 homes evacuated as a precaution. Well was leaking from brandenhead or/the casing annulus. H_2S was monitored the entire time.
11/2/2007	Kinder Morgan Production Co LLC	SACROC Unit	Kelly-Snyder	Scurry	N	N	N	0	Bottom valve failed while changing out master valve on tree
6/25/2007	Kinder Morgan Production Co. LP	SACROC Unit	Kelly-Snyder	Scurry	N	N	0	0	Contractor broke casing nipple
6/14/2007	Kinder Morgan Production Co LP	SACROC Unit	Kelly-Snyder	Scurry	N	N	0	0	Operator snagged a valve on the well casing
2/15/2006	Kinder Morgan Production Co. LP	SACROC Unit	Kelly-Snyder	Scurry	Y		0	0	Pipe nipple blew out
2/12/2006	Kinder Morgan Production Co. LP	SACROC Unit	Kelly-Snyder	Scurry			0	0	Valve on tubing/casing annulus failed.
8/2/2004	Kinder Morgan	SACROC Unit	Kelly-Snyder	Scurry		N	0	0	Sub pump mandrel corroded
2/11/1985	Chevron	SACROC Unit	Kelly-Snyder	Scurry	N	N	0	0	No notes

Table 2: Blowouts and well control problems reported to the UIC class II (RRC, 2021b).

SACROC, like many other fields in the Permian basin, contains trace amounts of H_2S, which requires use of compatible materials in wells, flowlines, and other equipment and appropriate health and safety procedures at the surface. Kinder Morgan has also hosted a number of field trips for professionals to educate other operators about their operational practices, and provides training on health and safety prior to field access. A study of a well from SACROC that had been exposed to CO_2 showed alteration of cement but no loss of integrity (Carey et al., 2007).

In the DOE-funded study, many groundwater wells above and also around the SACROC CO_2 operations were repeatedly sampled (Smyth et al., 2006). The study found that although the groundwater chemistry was complex and variable because water from two Dockum and Ogallala aquifers were comingled in wells screened across both aquifers, distinctive cross-plots allowed the identification of introduced CO_2. However, with the possible exception of one poor quality sample, no evidence of introduced CO_2 or other water quality degradation over SACROC was identified.

2.10. West Hastings

The West Hastings Field in the Frio Formation of the Gulf coast of Texas was a prolific producer of both oil and gas after discovery in 1934; however, by 2000 it has been resold a number of times as it was considered an economically marginal stripper operation where very large volumes of water were produced to recover only a small amount of oil. Denbury exercised a purchase option in 2006 and completed the purchase in 2009 as part of a regional plan to expand their EOR to a number of fields using their newly built 320-mile, 24-inch-diameter CO_2 Green Line pipeline system (Figure 28). The Green Line is anchored at a major natural CO_2 source at Jackson Dome, Mississippi; however, the natural CO_2 is augmented by several anthropogenic CO_2 sources, including a fertilizer plant at Donaldsonville (Louisiana). For the Hastings field, offtake was allocated in mass balance terms to the DOE-supported Air Products Industrial Capture project. This facility captures approximately 1 Mt per year of CO_2 from a steam methane reformed hydrogen plant operated by Air Products within the Valero refinery in Port Arthur, Texas. The Air Products facility started CO_2 deliveries in 2013. The Green Line also serves a number of other current and prospective CO_2 EOR projects such as Oyster Bayou field.

Figure 28: New dedicated CO_2 pipeline the Green Line built by Denbury to collect anthropogenic CO_2 from sources in Louisiana and Texas and integrate them with the natural source of CO_2 from Jackson Dome (Denbury Resources Inc., 2008).

The West Hastings reservoir formed over the Hastings deep-seated salt structure. The field produces hydrocarbons at multiple depths and throughout the Oligocene–Miocene section (Figure 29). The CO_2 flood was started in the Frio Formation on the west side of the field, which is isolated by a major north–south-trending crestal graben. Facies are typical of the Houston Delta system supplied by streams similar to those that currently supply sand to the area (Galloway et al. 1982). Sands were reworked at the gulfward extent. Interlobe mudstones deposited in back barrier and delta plain settings separate the sand bodies into stratigraphically defined reservoir compartments. The top seal of the Frio is the regional Anahuac shale, which was deposited in marine settings as pro-delta mudstones and shelf sediments during a major regional marine transgression.

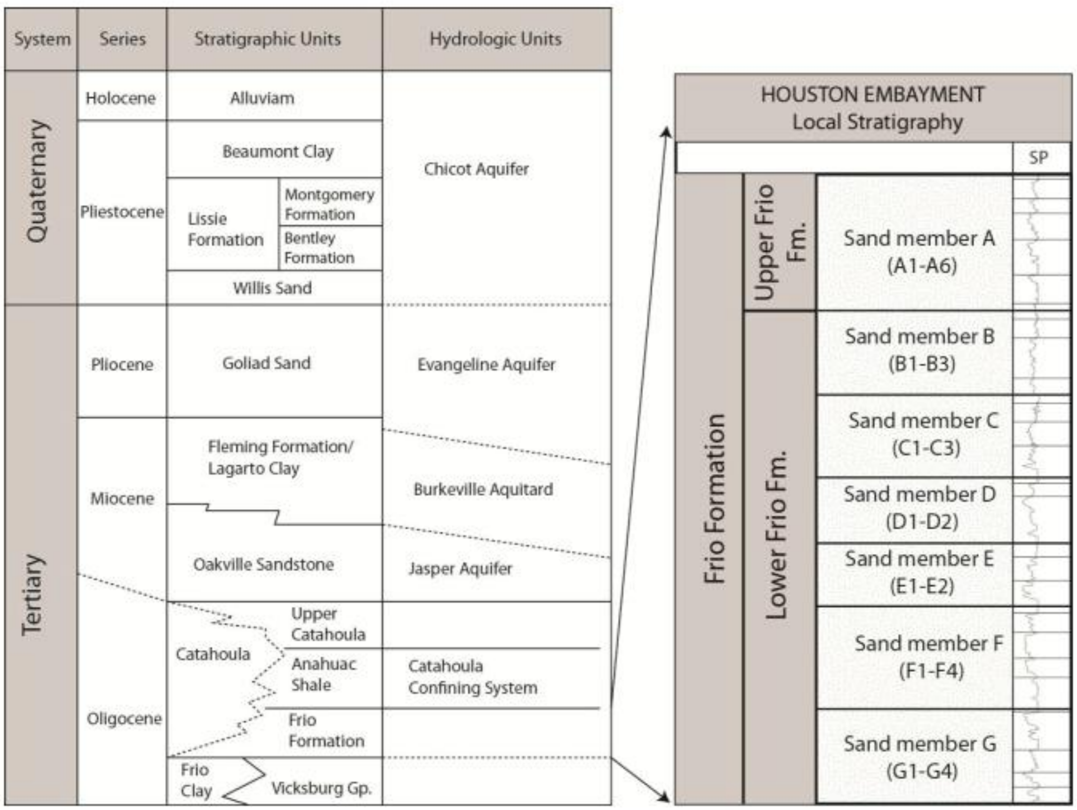


Figure 29: Type log showing location of the Frio Formation beneath the Anahuac Shale and the multiple Frio sandstones, most of which served as injection zones for CO_2.

The West Hastings is also segmented into mostly isolated compartments by radial faults around the salt structure and compartmentalized vertically into flow zones separated by mudstones (Figure 29 to Figure 31). The CO_2 project was designed to separately flood each of these compartments by its own patterns of injection and production wells. Most wells in the project are vertical, with some deviated wells to access the highly compartmentalized flow system. The reservoir can be considered a stacked system where CO_2 is emplaced into many different zones, each zone in large part acting as its own storage element but achieving scale in terms of shared infrastructure (pipeline) and surface and monitoring facilities. Faults are complex in three dimensions; however, eastward-dipping main graben faults extend to near the surface over the field area.

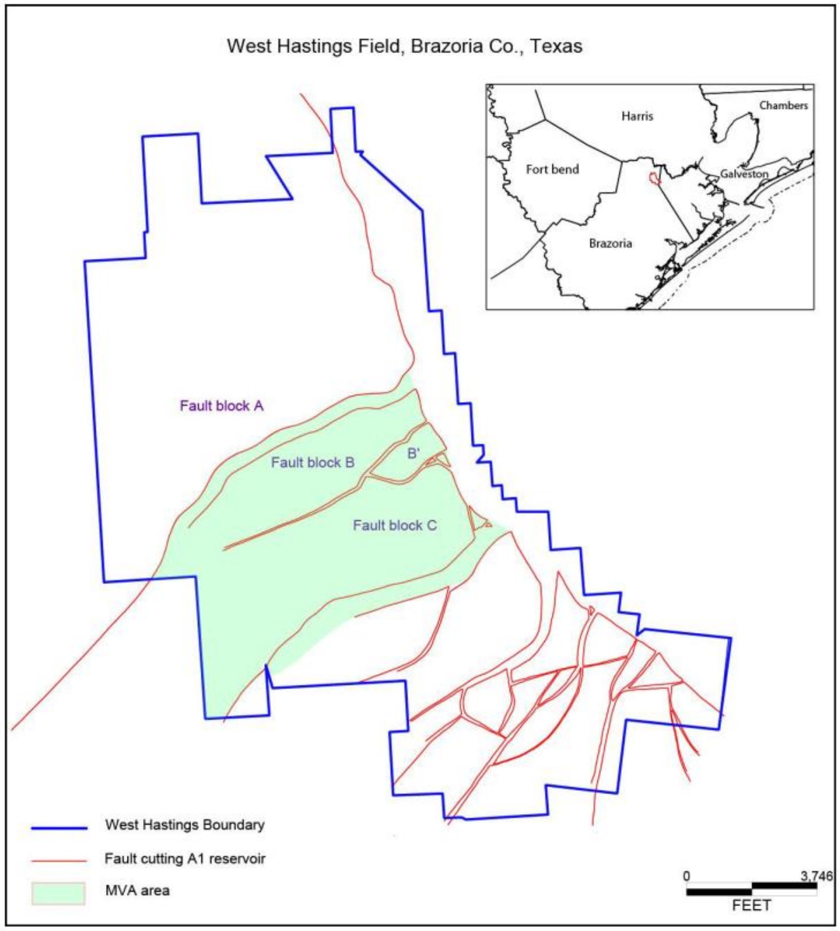


Figure 30: West Hastings field area and the focused monitoring area for the DOE-funded project in fault blocks B and C.

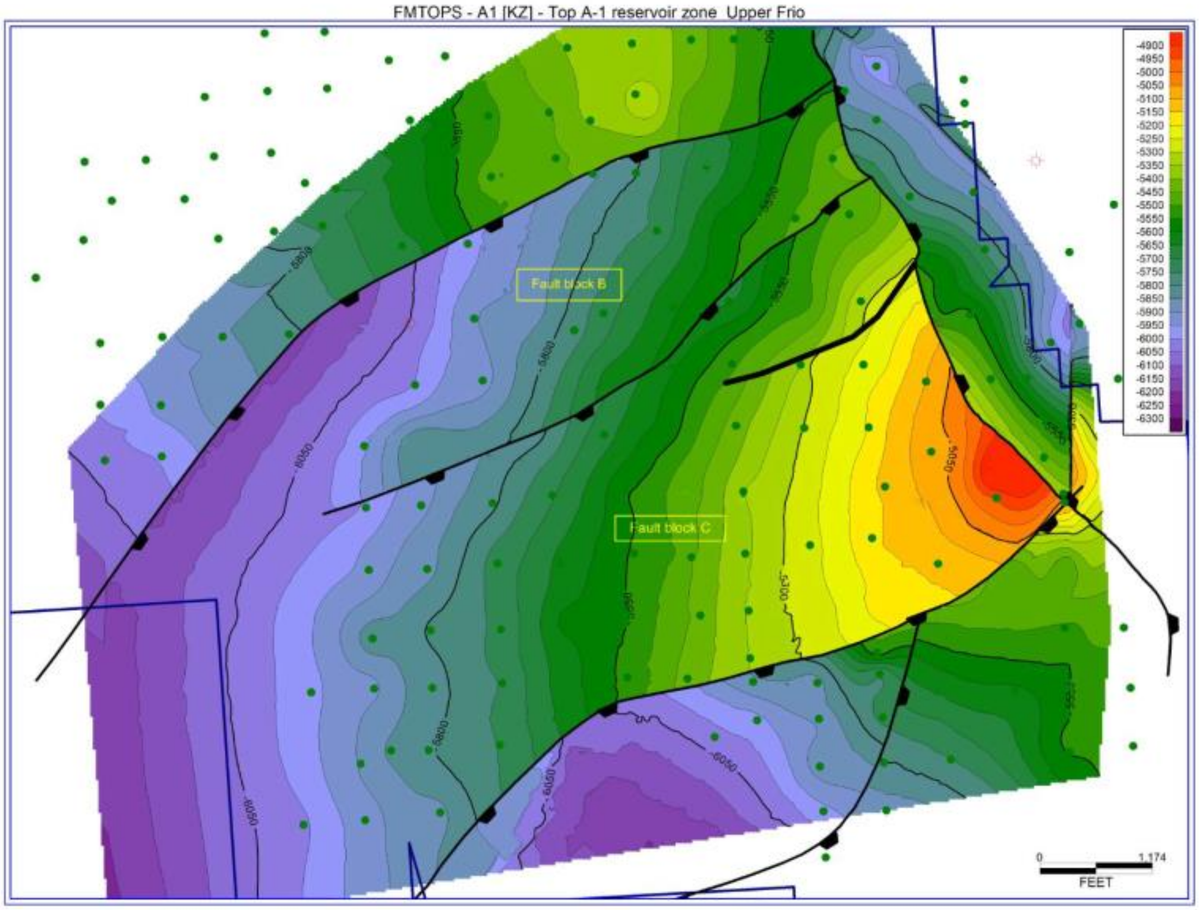


Figure 31: West Hastings field detail showing well control of the structure of fault blocks B and C, with the western fault of the graben on the east edge and radial faults further compartmentalizing the reservoir (Unpublished BEG report).

The fraction of the CO_2 (about 1 Mt per year) sent from the DOE-funded Air Products capture facility was nominally for the "B" block of the West Hastings reservoir, the focus of monitoring activities. In actual fact, the captured CO_2 was comingled with CO_2 from other sources in the pipeline and injected in multiple fields. Monitoring focused on tool testing, a gravity survey, above-zone monitoring, and a study on time-lapse fluid compressibility. Denbury flooded each fault-bounded reservoir compartment sequentially. They installed injector-producer patterns with different completion depths to flood the reservoir and concurrently produce from various but separate stratigraphic zones in each fault block (Figure 29 and Figure 32). In effect, a stack of separate EOR projects were undertaken simultaneously, to minimize the need for new CO_2 distribution facilities the size of the monitoring area.

This field is characterized by abundant faults, and deformation extends to near the surface. The large graben-cutting bounding faults offset the top-Frio Anahuac Formation significantly, an offset that can also be recognized in the Miocene section. No 3D seismic survey was available for the monitoring project, so the question of how to demonstrate seal integrity is relevant. One indirect method is the existence of multiple hydrocarbon charged zones is strong evidence that CO_2 will be retained. However, pre-seismic exploration methods detected a hydrocarbon geochemical signal that was strong early in the field development, in 1946, but after production, by 1968, the signal had attenuated (Horvitz, 1969). This might be interpreted as a seepage response. More work is needed to understand the value of faults as isolation.

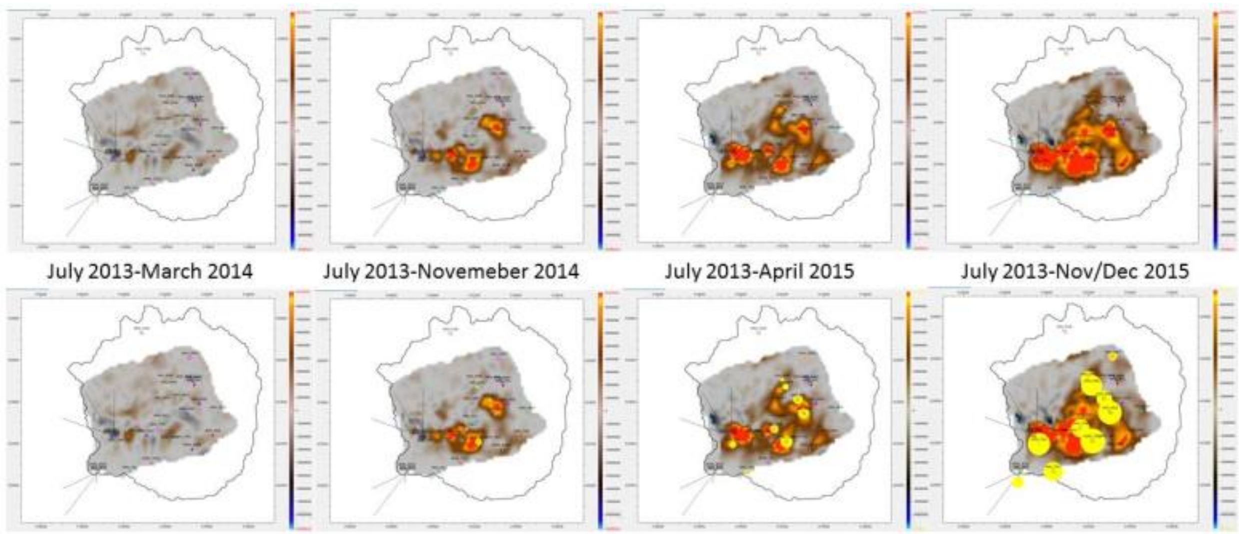


Figure 32: Results from time-lapse vertical seismic profiling (VSP) showing in bright colors the change in acoustic response interpreted as CO_2 replacing brine. The bottom row has superimposed yellow circles showing the volume of CO_2 injected (from Dok et al., 2016).

2.11. Wasson (Denver unit)

The Wasson field, discovered in 1936, was organized into seven units for pressure management by the Wasson Field Engineering Subcommittee in response to pressure depletion as a result of primary production. The Denver unit described here was unitized in 1964 (Tanner et al., 1992). Unlike some fields, the units are administratively divided but are not separate reservoirs in terms of fluid flow. CO_2 injection for EOR began at the Denver unit in 1983. Tanner et al. (1992) provide details on flood design including continuous gas and WAG injection, connections to the separation plant, and reservoir response. The Denver unit occupies most of the top of the geological structure, and other CO_2-EOR operations are now conducted in adjacent units of the Wasson field (Figure 33). By 1991, 91% of the unit oil column was under CO_2 flood, with the exception of some areas within city limits (Figure 34). Agreements for operations along lease lines were negotiated with adjacent operators (Tanner et al., 1992).

In 2000, Occidental Permian Ltd. (Oxy) took over operations (*Figure 35*). Carbon dioxide is captured from the gas processing plants of the Val Verde basin. In 2015, Oxy completed negotiations that established the intent, plan, and documentation for long-term containment of CO_2. This took the form of negotiating and obtaining approval from the US Environmental Protection Agency of Oxy's monitoring, reporting, and verification (MRV) plan, based in large part on Oxy's existing practices for field management, to meet the expectations of the US Clean Air Act Subpart RR greenhouse gas reporting rules. Oxy's plan was the first such MRV plan in the context of greenhouse gas reporting rules provided publicly in the United States.

Oxy provided an overview of their methods for managing EPA's list of risks affecting containment in depleted fields.

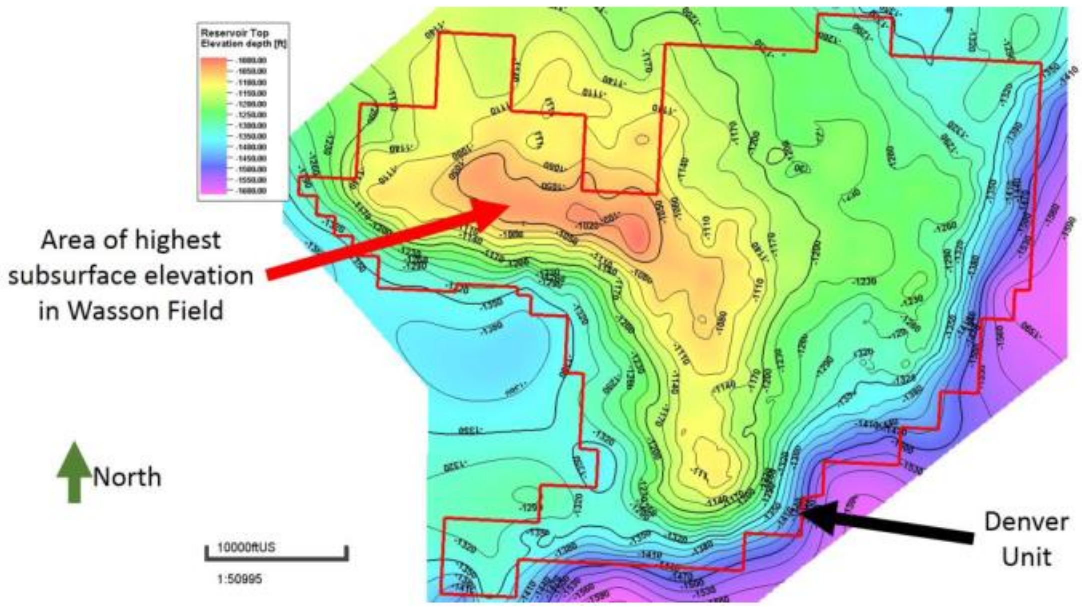


Figure 33: Structure on top of the San Andres reservoir in the Denver unit showing that it lies at the crest of the Wasson field (from EPA, 2015).

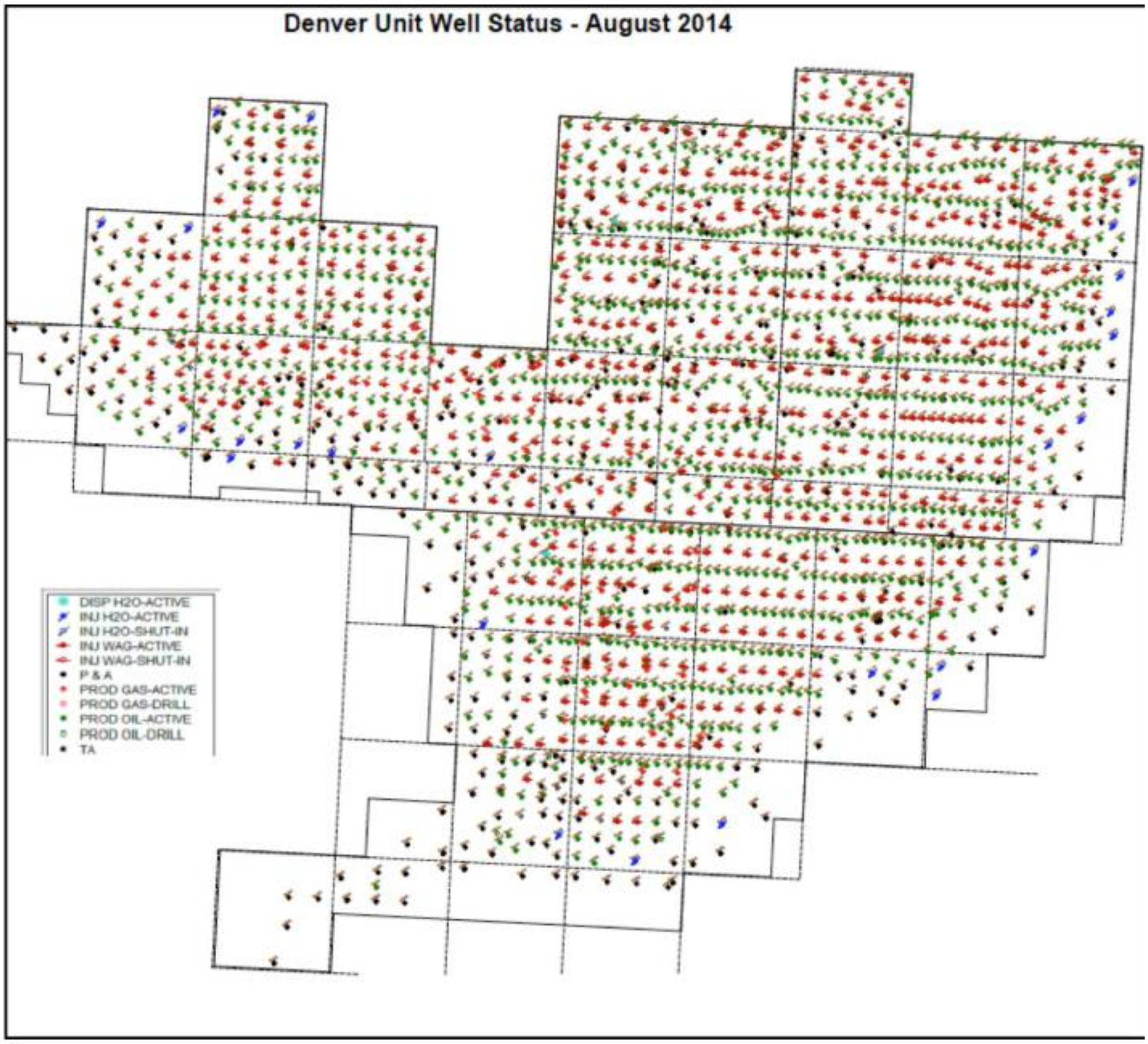


Figure 34: The Denver unit is densely drilled all the way to the unit boundaries. Red dots are injection wells for water and CO_2, green dots are production wells (From EPA, 2015).

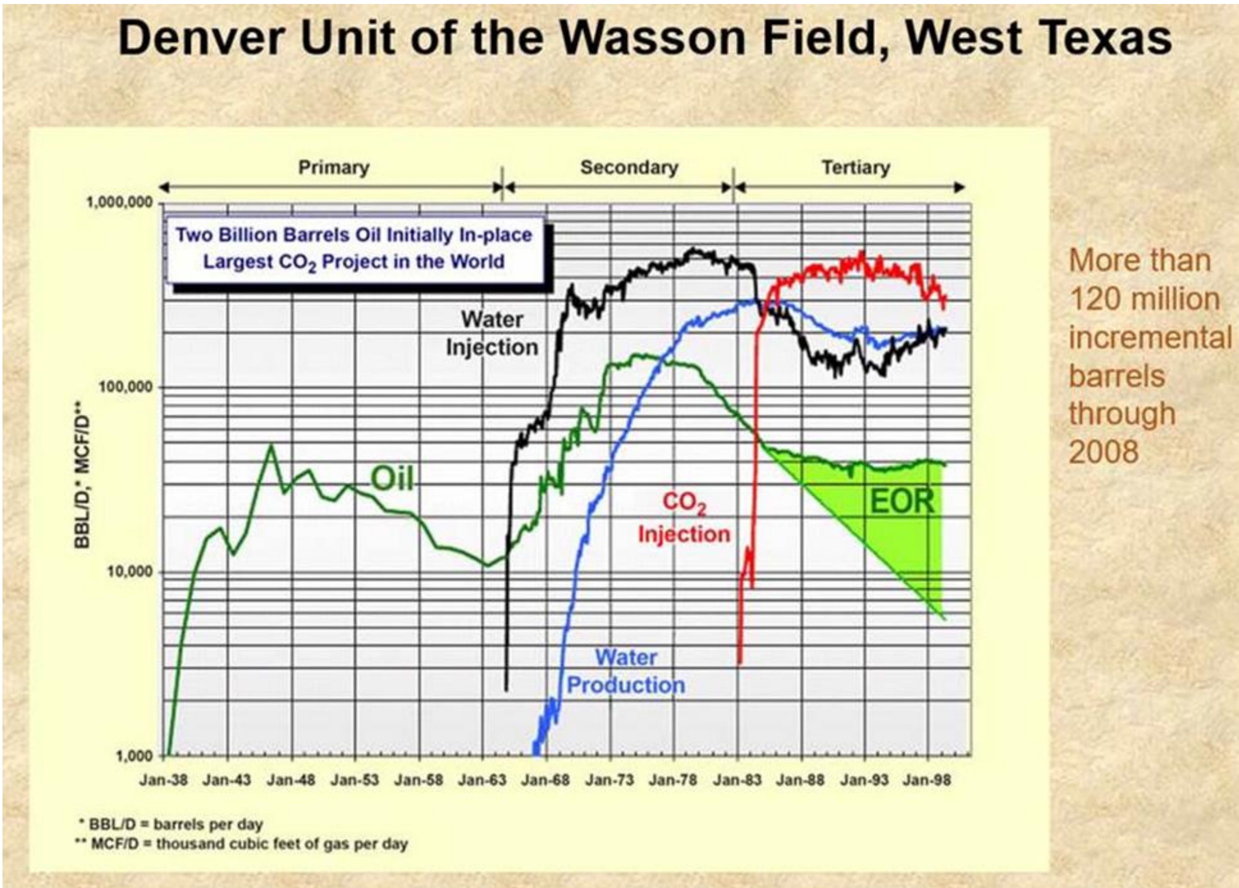


Figure 35: Overview of the production history of Wasson field, from Larry Lake (written communication).

The Wasson field has been the subject of a number of studies. The San Andres Formation, although more than 100 m thick, is composed of many high-frequency carbonate depositional cycles, giving it a relatively low ratio of vertical to horizonal permeability (Kv/Kh) (Figure 36) (Hsu et al., 1997). During deposition of the Permian San Andres Formation, the Wasson field was at the southeast margin of the Northwest Shelf of the Permian Basin. The Permian Basin was formed by complex faulting of basement and lower Paleozoic rocks across where subsidence during Permian deposition was slower on the margins and Central Basin Platform than in the Midland and Delaware Basins. This differential subsidence had a subtle impact on the San Andres carbonate and evaporite depositional facies, creating shoals and supratidal flats on uplifted areas that transition into more open marine facies off structure (Figure 36). Carbonate reservoir facies of the San Andres Formation include grainstone and packstones, which were deposited on a very low relief ramp in an epicontinental sea. The San Andres Formation in Wasson field was extensively dolomitized and contains variable amounts of anhydrite cement and anhydrite nodules. During the post-depositional period, continued differential uplift with the same general sense of motion resulted in development of a series of low-relief northwest–southeast-trending echelon uplifts on the Central Basin Platform and Northern Shelf, over which the San Andres reservoir is draped. In seismic sections, faults imaged at depth are expressed only as drape without offset at the reservoir zone (Oxy, 2015).

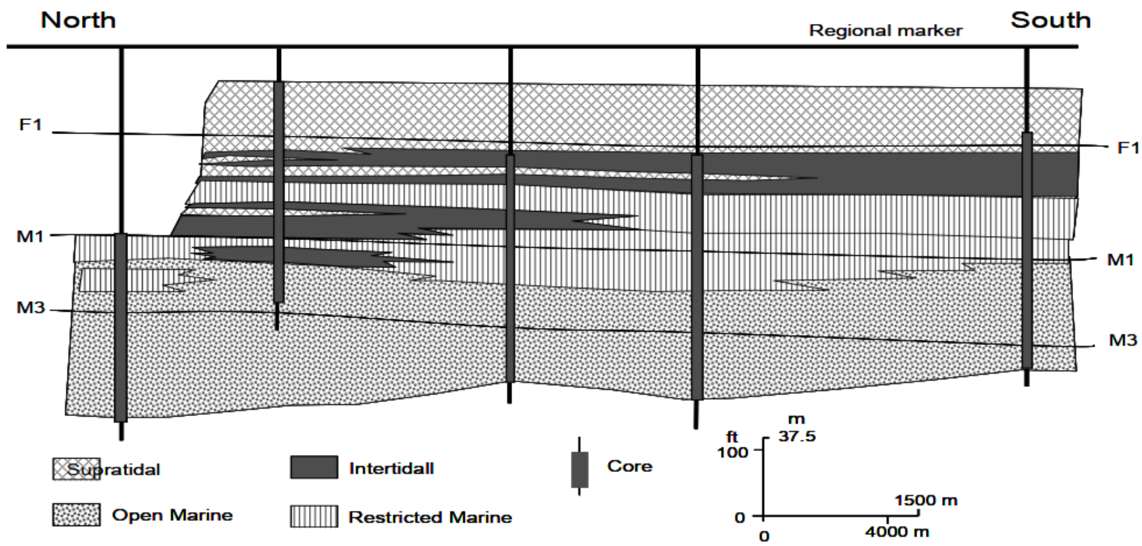


Figure 36: North–south cross-section illustrating the depositional facies in the Denver unit across Wasson field. Mathis et al. (1986), from Quijada (2005).

The 500–800-m-thick San Andres reservoir is operated in three zones: "First porosity" is gas charged at the crest of the structure and less permeable than the underlying "main pay." Oil is also found in a thick zone beneath the base of conventional oil production. This zone was known as the "transition zone" (Hsu et al., 1997) or is also recognized as part of a play found in many other San Andres fields, the Residual Oil Zone (ROZ). The ROZ was once oil charged, but oil was naturally swept out of the trap during basin tilting and uplift. Remaining oil at residual saturation in the ROZ is also a candidate for CO_2-EOR in the same way that a field depleted by production is.

The MRV plan provides an item-by-item review of EPA's inventory of risks to retention including existing well bores, faults, and fractures; natural and induced seismicity; pipeline and surface equipment; lateral migration outside the Denver Unit; drilling through the CO_2 area; and diffuse leakage through the seal. The approach taken in the MRV plan was to provide information indicating why each issue is not expected to be problematic for the Denver unit.

EOR is distinct from a saline injection because some wells are dedicated to oil extraction. These producers also extract brine and CO_2 and other gases mixed with the oil. The mixed gases are sent to the processing facilities, where they are separated. Oil is sent to market, water is reinjected into the field to maintain pressure and support continued production, and CO_2 is cleaned, compressed, and reinjected. The MRV plan (EPA, 2015) has an appendix containing a detailed inventory of the wells in the unit. The production of each well is tested at least every two months, when produced fluids are piped to a satellite test facility where oil, water, and gas are measured. Oxy reports 1000 production wells and 32 satellite stations.

In 1975, prior to the commercial CO_2 flood, an accident in Atlantic Richfield Company's (ARCO) surface operations supporting an EOR pilot using CO_2 containing 4% H_2S resulted in nine deaths as the result of a wellhead leak (Swindle, 1975). This accident provided a strong incentive in the USA and the industry for developing health and safety plans for handling fluids that contain H_2S. In the Wesson field, H_2S is a more dangerous hazard when compared to CO_2 because loss of containment and accidental release of H_2S has a high impact in terms of health and safety and corrosivity at even very low concentrations. Wasson recycle gas contains 2000-500 ppmv H_2S and management of this risk is naturally part of the health and safety program for workers. In the MRV plan, the highly sensitive detection equipment used to protect workers is proposed to do double duty to document that no leakage from depth is occurring.

2.12. Discussion

The case studies presented here illustrate the wide range of “depleted field” storage. It ranges from fields that are actively producing (somewhat depleted) to post-production (“fully depleted” as determined by highly variable, site-specific economic or operational criteria). CO_2 injection may be into the hydrocarbon reservoir or down-dip in the water leg, creating a wide spectrum of potential hydrocarbon saturations at the point of injection. Similarly, observed reservoir pressures at the start of injection range from highly depleted to hydrostatic. Thus “depleted” does not necessarily mean that either hydrocarbon reserves or pressure have been entirely depleted, nor does “storage” necessarily mean that hydrocarbon production has finished. Cases like the Lacq or Otway projects that inject CO_2 directly into a post-production hydrocarbon reservoir are perhaps the stereotypes of depleted field storage, but they are far from the only type referred to as “depleted field” storage, as the cases described here show. Some authors make a distinction between these scenarios (e.g., Hannis et al., 2017), others simply refer to them all as depleted fields (e.g., Paluszny et al., 2020). In concept, the spectrum could also include injection into wet reservoir levels within an existing field, particularly if they were deeper than producing reservoirs and therefore backstopped by the same proven seal. It also begs the question of how far down-dip an injection well could be sited before it was deemed saline storage unconnected with a depleted field. The broader point is that there is no single definition of storage in depleted fields, which creates both flexibility for operators contemplating storage design and a need for clarity among researchers discussing them.

It is also worth noting the striking regional differences in the current state of practice between CO_2-EOR and pure storage. There is well over a century of science and experience in hydrocarbon exploration and production and about five decades of experience in CO_2-EOR, resulting in large volumes of stored CO_2. In the United States, transitioning oil fields from waterflood to CO_2-EOR is fairly routine. Permitting is handled by state regulators and the process includes the opportunity for public comment. Thus far however, public opposition has been small and has never gained traction with regulators, as the case studies illustrate. By contrast proposals to use depleted fields for CO_2 storage in onshore Europe have faced significant public opposition and ultimately failed to gain regulatory permission to proceed. Altmark, as detailed here, is one such example. The Barendrecht field in the Netherlands is another (Herzog, 2016). In both regions, the first pure storage projects have been permitted and more are in planning and characterization (Global CCS Institute, 2020). Particularly in the United States, pure storage projects are subject to far more stringent permit review and ongoing monitoring than CO_2-EOR projects. Casting storage projects as CO_2-EOR may offer an easier path to permitting and/or public acceptance, at least in the United States. Although CO_2-EOR projects have different goals and different monitoring requirements as compared to pure storage projects, they can sequester large volumes of CO_2. There is significant operational experience in existing CO_2-EOR projects and learnings that can be applied to pure storage projects. Some of those insights are in the public domain, as reported here, but there is a great deal of experience that remains behind company doors.

By contrast, post-production CO_2 storage in depleted fields is in its infancy, permitting maturity is highly variable and public acceptance is far from given. In geologic and operational terms, there is some similarity between CO_2-EOR and post-production injection into depleted reservoirs. Indeed, the case studies presented here illustrate those similarities and are valuable in confirming and extending the science, particularly around monitoring. In terms of advancing deployment of CCS however, their most valuable contribution is perhaps in pioneering regulation and building public trust. Site-specific factors and the attitudes of local communities and government officials will always play a large role but the commonalities among projects described here suggest ingredients for success. Early, continuous and transparent communication appear to be key as do openness and collaboration. Even successful projects such as Otway and Lacq faced challenges and unsuccessful ones such as Altmark illustrate the potential significance of public opposition. Given sufficient experience, it seems likely that assessment, public acceptance and permitting of pure storage projects will become as routine as it is for CO_2-EOR. At this stage however, missteps and accidents have the potential to create outsize setbacks for storage.

On a more technical level, the case studies illustrate some of the challenges in depleted field storage. Low-injectivity reservoir may be thoroughly adequate for some projects but the experience of In Salah shows the potential difficulties when it is mismatched with the project requirements. Trying to inject more than the reservoir can comfortably accept requires high injection pressures and raises the risk of induced seismicity and/or leakage, particularly through faults or fractures (Bissell et al., 2011; Ringrose et al., 2013; Hoffman et al., 2015). In principle, this risk can be minimized if an operator can locate the injector(s) sufficiently far from faults and fractures that reservoir fluid pressure on those faults and fractures remains below virgin pressure (proven safe by the presence of the original hydrocarbon accumulation). The absolute risk may thus be low but it still requires careful evaluation and the greater the number of natural faults or fractures in a site, the more time-consuming such an evaluation may be. As operators and regulators gain experience with CO_2 sequestration, these risks will doubtlessly become better understood and evaluation will become more targeted and streamlined. Until then, selecting fields with injectivity matched to project requirements is highly recommended.

In terms of containment security, all varieties of depleted field described here can offer safe, long-term storage. Ideally, candidates for storage would be geologically simple (low structural and stratigraphic complexity) and have multiple sealing horizons, offering redundant containment. Even without those attributes however, the fact that a depleted field has retained hydrocarbons over geologic time is powerful evidence of its ability to contain buoyant fluids. Starting with that observation, there are three possibilities for leakage that bear investigation:

- Some hydrocarbon fields do leak (e.g., Hao et al., 2009, 2012). If evidence of hydrocarbons is observed in the overburden above a candidate storage reservoir, it is worth trying to determine the migration path and the rate of leakage, if they are in fact leaking from the proposed storage reservoir. Even then, geologic leakage rates may be perfectly acceptable for century- or millennium-scale CO_2 storage, so long as monitoring is in place to verify limited rates.
- Injection-related pressure build-up may stress potential leak points beyond their proven limits. The two safest scenarios in this respect are CO_2-EOR and storage in pressure-depleted fields. In the former case, the injection-withdrawal ratio (IWR) can be managed to maintain reservoir pressure within proven safe limits. In the latter case, pressure depletion offers room to cease injection before exceeding virgin pressure (proven safe) or hydrostatic pressure (creating a pressure barrier as well as the geologic barriers to leakage).
- Critical containment elements may degrade over time. There is little evidence that CO_2 will degrade geologic seals over the timescale of storage projects (e.g., Kampman et al., 2016) and remaining gas may even create an inert buffer between stored CO_2 and the seal horizon (Thibeau,

2013). The more likely risk is degradation of legacy well integrity over time, not even necessarily related to contact with CO_2. That risk must be evaluated on a well by well basis.

K12-B illustrates some of the challenge of repurposing infrastructure. Even with a single operator and a relatively new well, unanticipated scale resulted in a failed log run and much concern about casing integrity (Vandeweijer et al., 2011). More positively, it is worth noting that among all the case studies presented here, there was only one well that showed evidence of possible CO_2 leakage (In Salah) and work at Altmark illustrated the possibility for halites and anhydrites to heal defects in cement jobs (Kuhn et al., 2012; Ringrose et al., 2013). The studies reviewed are an admittedly limited sample but the failure rate and the analyses done for these studies suggests that the risk of subsurface leakage through or along legacy wells may be low (e.g., Nicot et al., 2013).

More broadly, the case studies extend the science of monitoring and offer clear insights into the application of different techniques. Many of these have been reviewed before, based on some of the same case studies (IEAGHG, 2017) but the insights can be summarized as follows:

- 4D seismic: Limited value in tracking plume migration in depleted gas fields, as the contrast between methane and CO_2 is small in many settings. It may pick up injection-related changes in reservoir thickness (Ringrose et al., 2013) and it is excellent for spotting leaks into saline aquifers where the presence of gas-phase CO_2 creates a large acoustic impedance contrast (Jenkins et al., 2012; Cook, 2014). In some fields, sufficient acoustic impedance contrast between CO_2 and oil means that 4D seismic can be an effective monitoring tool in depleted oil fields, for example at Weyburn-Midale.
- Surface gas and water monitoring: Depleted fields have had both a geologic history of hydrocarbon accumulation at depth and a modern history of hydrocarbon production to the surface. Both of these histories create complexities at the surface in terms of anomalous hydrocarbons and in some cases degradation of hydrocarbons into CO_2. These brownfields can be difficult to monitor because of high and variable CO_2 prior to the start of the injection project (Wolaver et al., 2013). Often complicated by high seasonal and diurnal variations in CO_2 flux. In general, it is probably most useful for safeguarding against incidents and allegations (Hovorka et al., 2013; Ringrose et al., 2013; Dixon and Romanak, 2015).
- Pressure monitoring in the reservoir: Key to maintaining and updating reservoir models and useful for verifying that pressure is maintained within safe injection limits but it is unlikely to detect leaks (Hovorka et al., 2013; Prinet et al., 2013; Thibeau, 2013; Shi et al., 2019).
- Microseismicity: Cost-effective and key to attributing seismicity. It may be useful for tracking the plume under the right conditions (Prinet et al., 2013; Total, 2015) and it may be critical for verifying that injection stays within mechanical limits stipulated by the regulator (Oye et al., 2013).
- Surface elevation, tilt and InSAR: Cost-effective where surface and operational conditions are favorable. Needs careful processing and geomechanical modelling to make sense of the observations (Ringrose et al., 2013) but may be very useful in the right circumstances (Bohloli et al., 2018). The desert environment and lack of conflicting signals from water injection made it particularly useful at In Salah. Testing of surface elevation changes at Hastings was complicated by groundwater effects (Karegar et al., 2015).

- Monitoring wells: Offer unique insights (e.g., wireline logging fluid samples, pressure and temperature away from the injector). They are excellent for research (Jenkins et al., 2012; Hovorka et al., 2013) but potentially expensive and may not be universally needed (Total, 2015).
- Tracers: Important for tracking plume movement and updating reservoir models where there is naturally occurring CO_2 and production or monitoring wells are available (Vandeweijer et al., 2011; Jenkins et al., 2012; Monne, 2012; Ringrose et al., 2013). Most CO_2 soluble tracers are strong greenhouse gases and should be used with this in mind.

As ever, individual techniques are useful but they are most powerful in combination where they can be integrated to pinpoint causes (Cook, 2013; Hovorka et al., 2013; Shi et al., 2019). For example, measurements of saturation change made by logging a well provide high vertical resolution to assess the sweep efficacy, however time-lapse seismic monitoring provides the complementary information on spatial changes in CO_2 distribution. Information on pressure at depth from wells is highly qualitative; surface deformation can provide information on the region of elevated pressure.

3. Effect of Residual Fluids on Storage Efficiency

3.1. Introduction

Numerical simulation of CO_2 injection in geological models of realistic fields plays an important role in predicting, evaluating, and optimizing the CO_2 injection and post-injection performance prior to the commencement of an actual field operation. The majority of published numerical studies of CO_2 injection in depleted gas reservoirs have focused on investigating the combined contributions of CO_2-enhanced gas recovery (EGR) and CO_2 storage (Jikich et al., 2003, Oldenburg and Benson, 2002, Feather and Archer, 2010, Shen et al., 2014), while less attention has been paid to the re-use of depleted gas reservoirs solely for CO_2 storage (Snippe and Tucker, 2014, Raza et al., 2017, Raza et al., 2018).

Jikich et al. (2003) studied the effect of CO_2 injection on enhanced gas recovery (EGR) from a shaly sandstone reservoir located in northern West Virginia. Using numerical simulations, they applied two different CO_2 injection scenarios: CO_2 injection at (1) the early stage of gas production, and (2) primary gas production, followed by CO_2 injection for the secondary recovery. They found that the second scenario yields a better recovery of the gas in place (GIP). The study suggests that injection of CO_2 at a pressure higher than the reservoir pressure and utilizing horizontal injectors improves the storage capacity of the gas reservoir (Jikich et al., 2003).

Oldenburg and Benson (2002) performed a reservoir simulation study of CO_2 storage and EGR in a depleted gas reservoir applicable to the Rio Vista gas field in California. They showed that a significant improvement in the gas recovery can be obtained by injecting a large quantity of CO_2 into depleted gas reservoirs. According to their observations, the large density and viscosity contrast between CO_2 and CH_4 limits the mixing of the two, leading the CO_2 plume to accumulate mainly at the bottom of the reservoir (Oldenburg and Benson, 2002).

Feather and Archer (2010) numerically investigated the effect of parameters including reservoir permeability, reservoir geometry, well type, and injection rate on CO_2 storage and EGR. They found that utilization of vertical wells, a dipping geometry of the reservoir, and permeability anisotropy and heterogeneity are favorable factors for EGR productivity. Moreover, injection of CO_2 at the late stage of reservoir depletion and employing the maximum possible injection rate were recommended to improve CO_2 storage (Feather and Archer, 2010).

Shen et al. (2014) conducted a modeling study to investigate CO_2-EGR and CO_2 storage in a nearly depleted gas-condensate reservoir in Taiwan. Their study demonstrated the contribution of CO_2 displacement and condensate revaporization to gas recovery while showing the capability of CO_2 storage as CO_2 sank to the bottom of the gas cap under the effect of gravity (Shen et al., 2014).

Shell U.K. Limited did a comprehensive study on the depleted North Sea Goldeneye field including site characterization, site capacity estimation, transportation and injection facilities, monitoring, and post-closure plans to demonstrate that this field has the capacity to store CO_2. According to this study, reservoir heterogeneity, residual water saturation, CO_2 mixing with hydrocarbon gas, CO_2 dissolution in brine, buoyancy filling of the overlying Captain E sand, and capacity of the water leg are the uncertain factors for the estimation of Goldeneye CO_2 storage capacity (Shell U.K. Limited, 2016).

Snippe and Tucker compared the CO_2 trapping efficiency of depleted gas fields (a structurally closed setting) and dipping saline aquifers (a structurally open setting) using simple reservoir simulations. In all the cases that they studied, the CO_2 plume is mainly a mobile gaseous phase, followed by dissolved CO_2, mineralized CO_2, and finally, capillary-trapped CO_2, which plays a minor role in trapping CO_2. They found that more than 50% of the CO_2 plume remains mobile even after 10,000 years of post-injection in the closed depleted gas reservoir (Snippe and Tucker, 2014).

A study by Raza et al. (2017) evaluates the CO_2 storage potential of an offshore depleted gas field in Malaysia. They quantified the effect of pressure, temperature, and salinity on the CO_2 residual trapping efficiency of the reservoir through numerical simulations. The study suggests that the amount of residually trapped CO_2 during the injection period increases as the salinity and temperature increase. They also found that the saturation of mobile CO_2 increases up to a certain value and then starts to decline until the effective pore volume is filled by the injected CO_2. Moreover, the residual gas saturation gradually declines as the pressure builds up during the injection (Raza et al., 2017).

In another study, Raza et al. (2018) investigated the effect of residual gas on CO_2 storage capacity, injectivity, reservoir pressure build-up, and CO_2 trapping efficiency occurring during storage of CO_2 in depleted gas reservoirs. They found that residual gas is one of the key factors affecting CO_2 storage performance, so reservoirs with lower levels of residual gas are better suited for storage. The study suggests that the remaining GIP improves CO_2 capillary trapping, while dissolution trapping and storage capacity are suppressed in the presence of the remaining gas (Raza et al., 2018).

The main goal of this section is to evaluate the storage capacity and trapping efficiency of CO_2 in depleted gas reservoirs and to consider the amount of residual hydrocarbon gas as a selection criterion for identifying a suitable storage site.

3.2. Reservoir simulation

The main goal of this simple numerical simulation is to evaluate the effect of residual gas on the storage capacity and trapping efficiency of CO_2 during its storage in a depleted gas reservoir. To this end, we initially simulate a gas depletion scenario and subsequently inject CO_2 for storage in the depleted reservoir.

The reservoir model was built using properties representative of the so-called “HC sand” as a typical example from offshore Texas. The Miocene-age HC sand is a natural gas–producing reservoir in the High Island 24L field, located in the offshore Texas State Waters. The reservoir properties are taken from a previous study (Ruiz, 2019). For simplicity, we only take a subset of an area of interest (AOI) that has been characterized in Ruiz’s study. The 3D simulation domain is divided into $40 \times 40 \times 20$ grid cells with zero dip angle (Figure 37). The horizontal extent of the model is defined to be $6000\ \mathrm{ft} \times 4000\ \mathrm{ft}$ $(1829\ \mathrm{m} \times 1219\ \mathrm{m})$, and the total vertical thickness is $200\ \mathrm{ft}\ (61\ \mathrm{m})$. The reservoir is located at a depth of $8000\ \mathrm{ft}\ (2438\ \mathrm{m})$. The average porosity ($\emptyset$) and horizontal permeability (K_h) are set to be 0.29 and $483\ \mathrm{mD}\ (4.77 \times 10^{-13}\ \mathrm{m}^2)$, respectively. The permeability anisotropy ratio ($\frac{K_v}{K_h}$, where K_v is the average vertical permeability) is set at 0.1. The model was initialized in its pre-production stage, initially filled with hydrocarbon gas (CH_4) and connate brine. The initial temperature of the reservoir was set at $176\ \mathrm{F}\ (80\ ℃)$. The initial reservoir pressure prior to gas production is considered to be hydrostatic at $3720\ \mathrm{psi}\ (25.6\ \mathrm{MPa})$. However, the reservoir pressure at the start of CO_2 injection is at the depleted stage. The salinity level of brine is assumed to be 2 molal. The gas–water contact level is considered to be at 8210 ft (2502 m) and the original GIP is estimated at 270 Bscf (7.6×10^9 m^3). The simulation model is considered to be closed, with no-flow boundaries and no hydrodynamic contact with an aquifer.

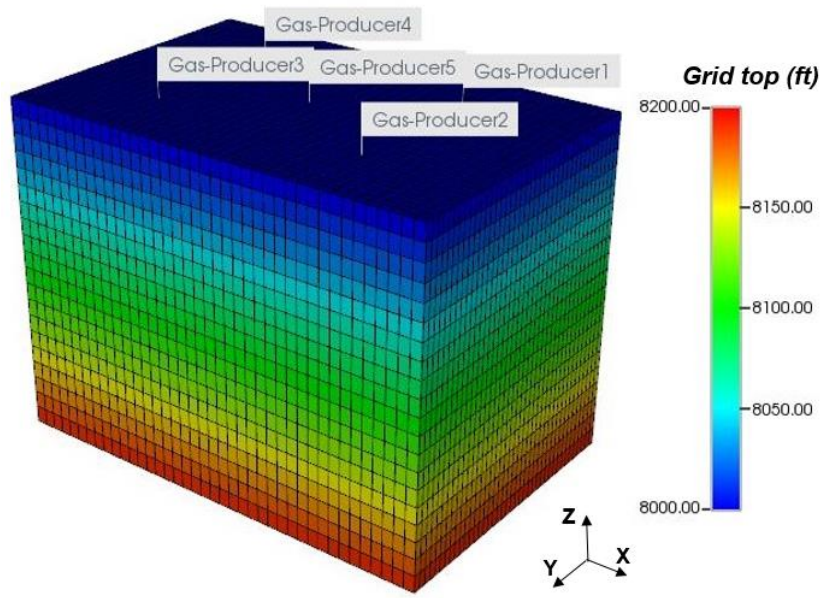


Figure 37: Reservoir model used for the simulations. Five producers are located in the reservoir with the perforation length of 70 ft (21 m) for the depletion simulations.

The liquid–gas relative permeability (k_{rl}, k_{rg}) and capillary pressure (P_c) curves as a function of liquid saturation (S_l) are shown in Figure 38. A Brooks–Corey model is used to generate the relative permeability curves, given by (Doughty, 2007; Oostrom et al., 2016)

$$k_{rl} = k_{rl}^{max}(S_l^*)^{N_l}$$

$$k_{rg} = k_{rg}^{max}(1 - S_l^*)^{N_g}$$

$$S_l^* = \frac{S_l - S_{lr}}{1 - S_{lr} - S_{gr}}$$

where S_l^* is the liquid effective saturation, and S_{lr} and S_{gr} are the connate water saturation and residual gas saturation at the end of the drainage cycle, respectively. S_{lr} is set to be 0.135 and S_{gr} is 0.2. N_l and N_g are the Corey's exponents for liquid and gas, respectively. k_{rl}^{max} and k_{rg}^{max} are the liquid and gas endpoint relative permeability. Brooks–Corey's parameters corresponding to liquid and gas drainage relative permeability curves are reported in
Table 3.

The capillary pressure is obtained using van Genuchten's model, given by (van Genuchten, 1980)

$$P_c = -\frac{1}{\beta}[(\frac{S_l - S_l^{min}}{1 - S_l^{min}})^{\frac{N_c}{N_c - 1}} - 1]^{(1/N_c)}$$

where β, S_l^{min}, and N_c are model parameters, reported in Table 3.

To account for the contribution of CO_2 residual trapping, we incorporate the hysteresis characteristics into the relative permeability curve. To model the gas relative permeability hysteresis, we applied Land's trapping model (1968), which relates the trapped gas saturation S_{gt} to the initial gas saturation S_{gi} during the imbibition (flow reversal from drainage to imbibition):

$$S_{gt} = \frac{S_{gi}}{1 + CS_{gi}}$$

where C is the Land trapping coefficient calculated as

$$C = \frac{1}{S_{gr}^{max}} - \frac{1}{S_g^{max}}.$$

S_g^{max} is the maximum gas saturation associated with the imbibition curve, and S_{gr}^{max} is the maximum residual (trapped) gas saturation that can be obtained during the imbibition stage. In this study, S_{gr}^{max} is assumed to be 0.25, and $S_g^{max} = 1 - S_{lr}$. In other words, the maximum achievable capillary trapped gas saturation is 0.25 at the imbibition stage.

Furthermore, dissolution of CO_2 in brine is added to the model through the use of Henry's law (Li and Nghiem, 1986). Finally, we employ the Generalized Equation of State Model Reservoir Simulator (GEM) from CMG-Computer Modeling Group (CMG-GEM, 2012) for the compositional simulations performed in this study.

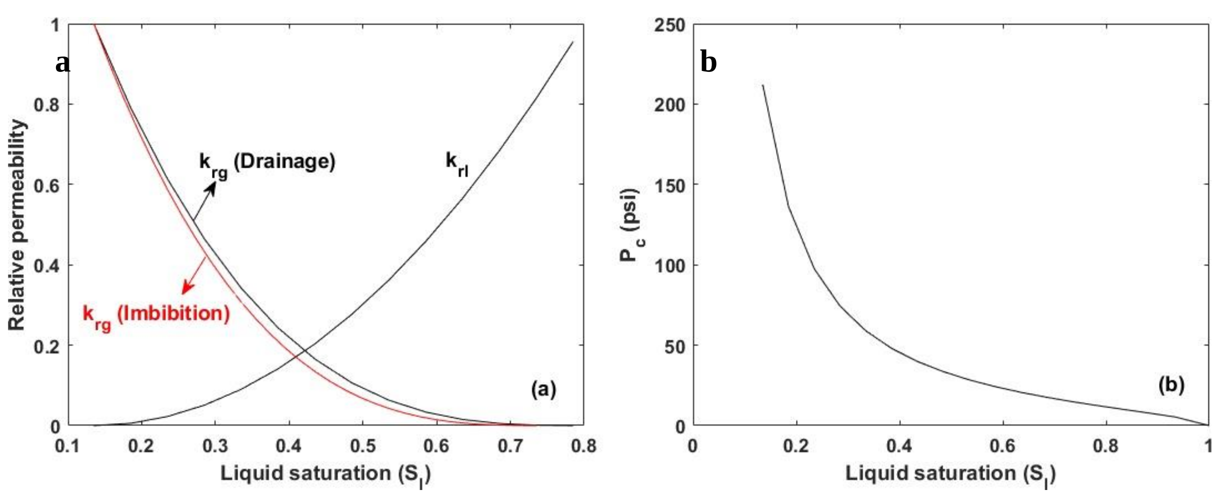


Figure 38: (a) Liquid–gas relative permeability curves and (b) capillary pressure curves used in the simulations.

Prior to the CO_2 injection scenario, we conducted several depletion simulations to achieve different recovery factors (RF) and hence, volumes of the remaining gas. Subsequent to the depletion scenario, CO_2 injection was performed, and no secondary recovery occurred. To run the depletion scenario, five production wells were placed in the reservoir, as shown in Figure 37. A minimum bottom-hole pressure of 200 psi (1.38 MPa) is assigned as a constraint for the production wells. Under different production scenarios, we varied the production time period to obtain different volumes of the remaining gas after depletion. Table 4 displays the values of the initial and remaining GIP, recovery factor, production time, and reservoir pressure obtained at the end of the depletion stage. Figure 39 represents the time evolution of the reservoir pressure and volume of GIP during the production stage for various ultimate recovery factors. According to the results, the gas volume and, consequently, reservoir pressure rapidly decline and reach a stabilized state, which occurs faster at smaller recovery factors.

After a desired gas recovery factor is obtained and reservoir pressure becomes stabilized, the production wells were shut in and CO_2 was injected into the depleted gas reservoir containing different levels of remaining GIP. Carbon dioxide is injected through a single well into the formation, with a maximum well bottom-hole pressure of 6400 psi (44 MPa). The maximum injection pressure is considered to be 80% of the rock fracture pressure, which is estimated to be 8000 psi (55 MPa) based on the lithostatic pressure gradient of $1 \frac{\text{Psi}}{\text{ft}}$ $(\sim 0.023 \frac{\text{MPa}}{\text{m}})$. For modeling purposes, we assume that the injection pressure should be less than the maximum allowable to avoid any geomechanical damage (Salimzadeh et al., 2018). Note that the assumption considered for the limit of fracture pressure is a simplistic one, as in reality even a small pressure perturbation well below the rock fracture pressure may cause faults to slip or fractures to nucleate and grow. The injector is located in the center of the domain, with a perforation length of 30 ft (9 m), equivalent to grid block nos. 7 through 9.

k_{rl}^{max}	k_{rg}^{max}	N_l	N_g	S_{lr}	S_{gr}	S_l^{min}	β	N_c
1	1	2	3	0.135	0.20	0.01	1	1.77

Table 3: Parameters used for the drainage relative permeability and capillary pressure models.

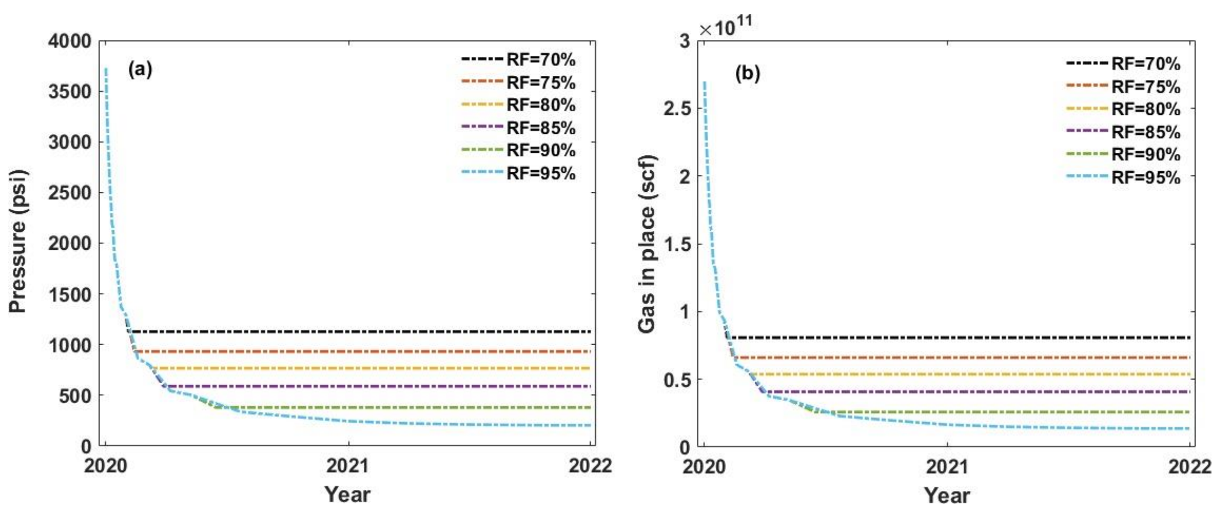


Figure 39: (a) Time evolution of reservoir pressure during depletion with different recovery factors. (b) Gas in place variation during depletion with different recovery factors.

Employing a volumetric method and knowledge of original and remaining GIP, we make a rough estimation of the CO_2 storage capacity of the reservoir. To make the estimation, we also applied an efficiency factor of 23%, as suggested in Ruiz's study (Ruiz, 2019). Using the estimated storage capacity, the maximum injection rate corresponding to the injection period of 10 years is calculated for each scenario (see Table 5). To ensure maintenance of a sustainable injection rate in all scenarios with different levels of remaining GIP, we have selected the minimum estimated injection rate ($12\ \frac{\mathrm{Mscf}}{\mathrm{day}} = 0.34 \times 10^6\ \frac{\mathrm{m}^3}{\mathrm{day}} = 622\ \frac{\mathrm{tons}}{\mathrm{day}}$) corresponding to the case with GIP=30% as a conservative choice and set it as the CO_2 injector constraint.

Original gas in place (Bscf)	Remaining gas (Bscf)	RF (%)	Production time (days)	Pressure (psi)
270	13.5	95	665	214
270	27	90	165	380
270	40.5	85	88	589
270	54	80	69	767
270	67.5	75	43	932
270	81	70	34	1128

Table 4: Original gas in place, remaining gas, and recovery factor (RF) after the depletion, production time, and reservoir pressure at the end of depletion.

RF (%)	Remaining GIP (%)	Static storage capacity (Bscf)	Injection rate ($\frac{\mathrm{Mscf}}{\mathrm{day}}$)
95	5	59	16
90	10	56	15
85	15	53	14
80	20	50	13.6
75	25	46	12.7
70	30	43	12

Table 5: Estimated CO_2 storage potential and injection rate for a 10-year injection period in the depleted reservoirs containing different levels of remaining gas in place (GIP) obtained under different recovery factors (RF).

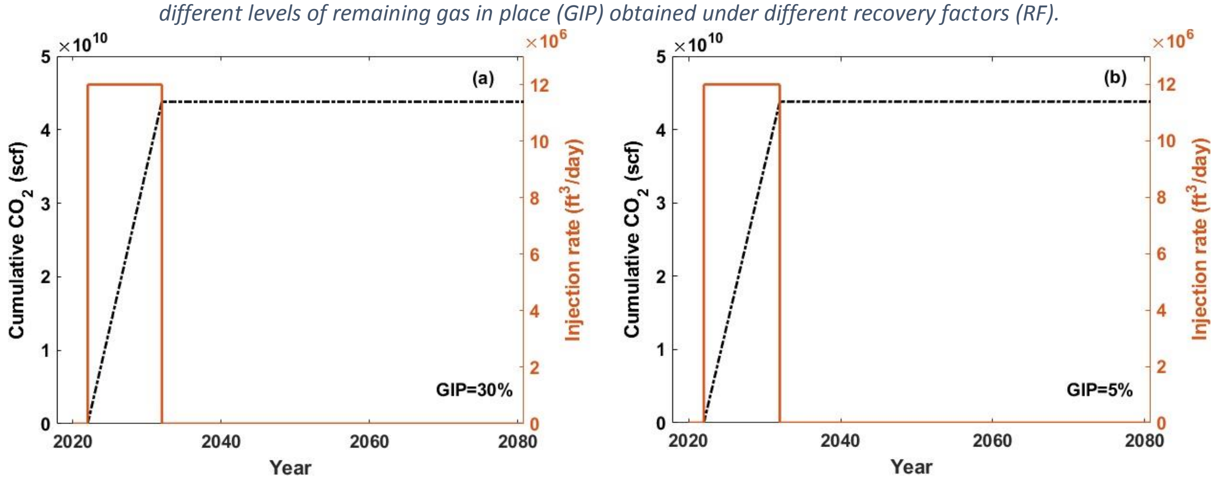


Figure 40: Time evolution of CO_2 injection rate and its cumulative stored volume in the depleted reservoirs with various remaining gas (a) GIP=30% and (b) GIP=5%.

We observed that the maximum predefined injection rate (12 $\mathrm{Mscf/day}$) can be maintained during the entire 10-year injection period for all scenarios, meaning that a sustainable injection can be achieved with no injectivity issue. For instance, Figure 40 shows the time evolution of injection rate and cumulative volume of stored CO_2 for GIP=30% and 5%. For all other scenarios, the same trend was observed.

We followed the CO_2 injection with 100 years of post-injection modeling. The 100-year period is selected arbitrarily only for evaluating the long-term behavior of the CO_2 plume in this study. This is not considered a recommended period of post-injection monitoring, as long-term post-injection monitoring is not required in a depleted reservoir with no-flow boundaries. Figure 41 compares the reservoir pressure build-up during the injection and post-injection periods under different remaining GIP volumes obtained under different recovery factors. As observed, the trend of pressure rise during the injection period is identical for different cases. Further, the maximum pressure build-up, which is observed under GIP=30%, is still below the maximum allowable bottom-hole injection pressure (6400 psi; $44\ \mathrm{MPa}$).

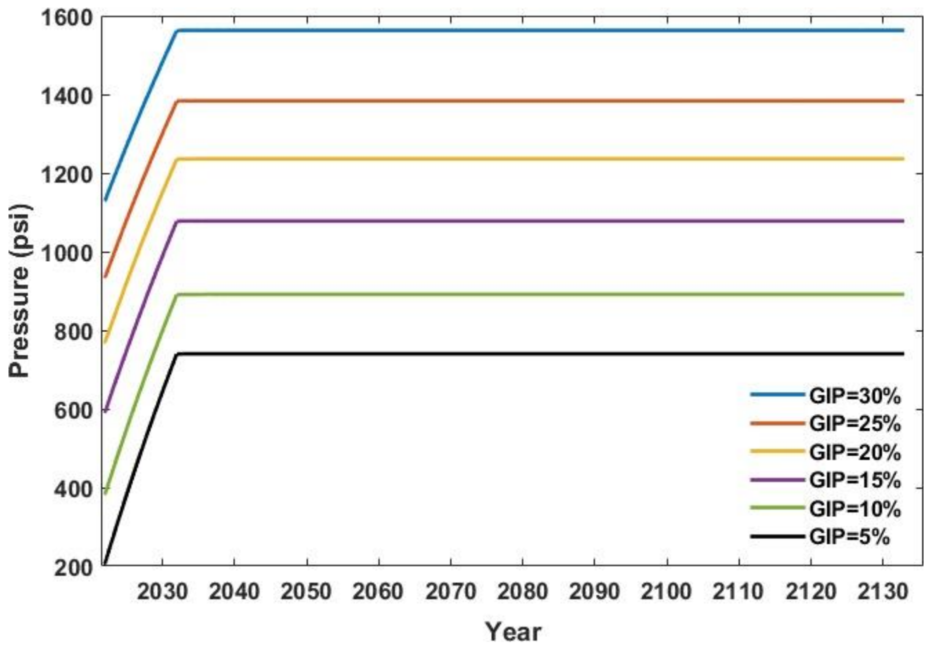


Figure 41: Time evolution of reservoir pressure during injection and post-injection periods in the depleted reservoirs containing various levels of remaining gas in place (GIP).

We further evaluate different trapping mechanisms of CO_2 in terms of mobile (free), residual, and dissolved CO_2 during the injection and post-injection periods. Figure 42 shows the volume of mobile, residually trapped, and dissolved CO_2 during the injection and post-injection stages in the depleted reservoirs containing different amounts of remaining GIP (30% and 5%). Figure 43 to Figure 45 display the percentage of stored CO_2 in the form of mobile gas, residually trapped, and dissolved CO_2 in reservoirs with different levels of remaining GIP. According to the results, the majority of the CO_2 plume remains mobile, followed by residual (capillary-trapped) CO_2 and then dissolved CO_2. Since brine exists at its connate saturation in the reservoir, dissolution of CO_2 in brine does not play a key role in the trapping of the CO_2 plume. Typically, imbibition of brine plays a key role in residual trapping of CO_2. In this study, because brine exists with its connate saturation and is immobile, there is no chance of imbibition. In other words, the observed residual trapping corresponds to the drainage stage, governed by the end-point drainage gas relative permeability. As can be seen in Figure 43 to Figure 45, the amount of remaining GIP does not significantly affect the residual and dissolution trapping of CO_2, and a large portion of the CO_2 plume remains as free gas (~74%).

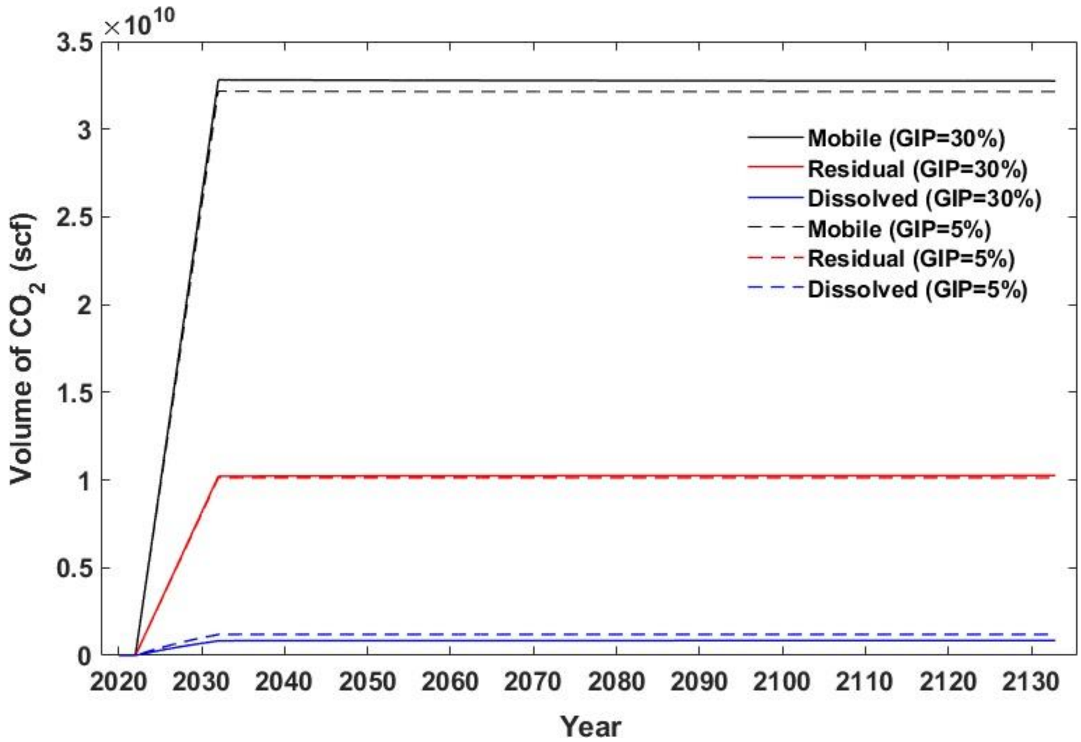


Figure 42: Time evolution of CO_2 volume stored in the form of mobile, residual, and dissolved CO_2 during the injection and post-injection periods in the depleted reservoirs containing different volumes of remaining gas in place.

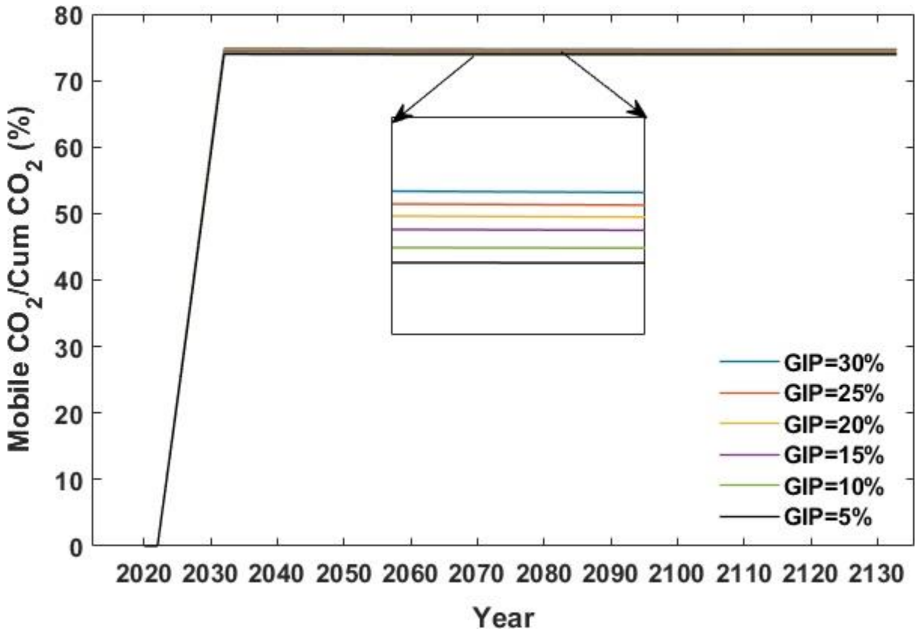


Figure 43: Percentage of stored CO_2 in the form of mobile gas during the injection and post-injection period in the depleted reservoirs containing different volumes of remaining gas in place. The inset shows a zoomed-in part of the plot.

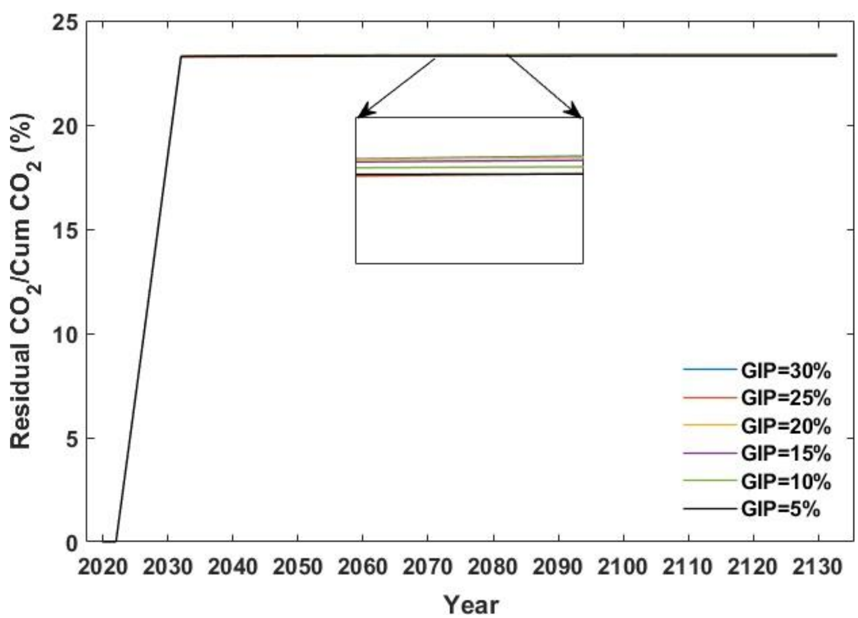


Figure 44: Percentage of stored CO_2 in the form of residual CO_2 during the injection and post-injection periods in the depleted reservoirs containing different levels of remaining gas in place. The inset shows a zoomed-in part of the plot.

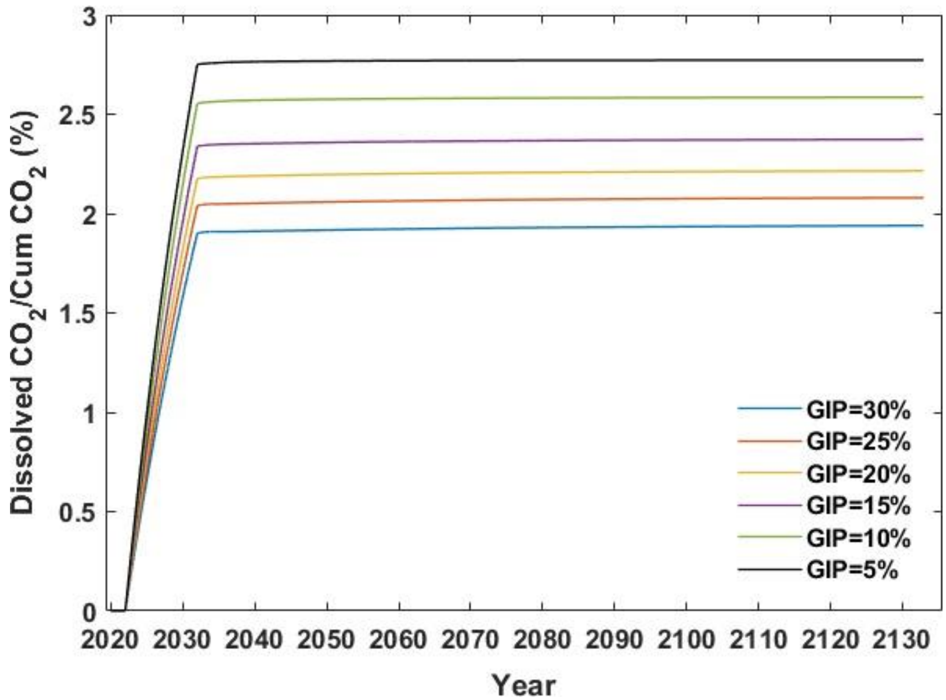


Figure 45: Percentage of stored CO_2 in the form of dissolved CO_2 during the injection and post-injection periods in the depleted reservoirs containing different levels of remaining gas in place.

Figure 46 shows spatial distribution of CO_2 saturation in a half-cut reservoir model of the depleted reservoir with GIP=30% and 5% at different times during the injection and post-injection stages. We observe that during the injection, the CO_2 plume tends to move upward due to buoyancy, but it never reaches the top of the reservoir with GIP=30%, as the reservoir is mainly filled with CH_4. After the injection stops, the CO_2 plume starts to recede and mainly fill the lower layers of the reservoir, while the layers close to the reservoir top are occupied by gas (CH_4). In other words, the lower density and viscosity of CH_4 relative to CO_2 favors the accumulation of CH_4 in the shallow depths of the reservoir. Furthermore, in the case with a higher amount of residual gas (GIP=30%), the CO_2 plume stabilizes in the lower depths close to the reservoir bottom. In general, the resident gas present in the depleted reservoir acts as a cushion to prevent the CO_2 plume from reaching the top sealing layer of the reservoir.

Figure 47 displays CO_2 and CH_4 saturation profiles along the reservoir depth (Z direction) in the 100 years after injection in the depleted reservoirs containing different remaining GIP volumes. These saturation profiles also confirm that the CO_2 plume accumulates in deeper depths of the reservoir as the volume of remaining GIP increases.

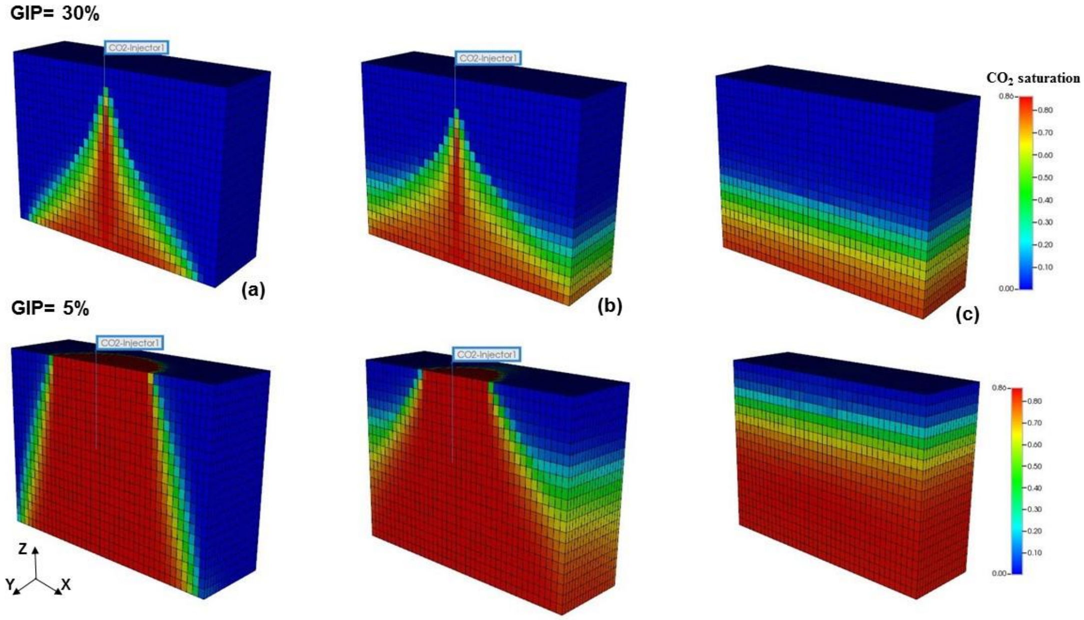


Figure 46: Spatial distribution of CO_2 saturation in a half-cut reservoir model of depleted reservoirs with GIP=30% and GIP=5% at different times. (a) Year 2026, (b) Year 2032 (end of the injection stage), and (c) Year 2132 (end of the post-injection stage).

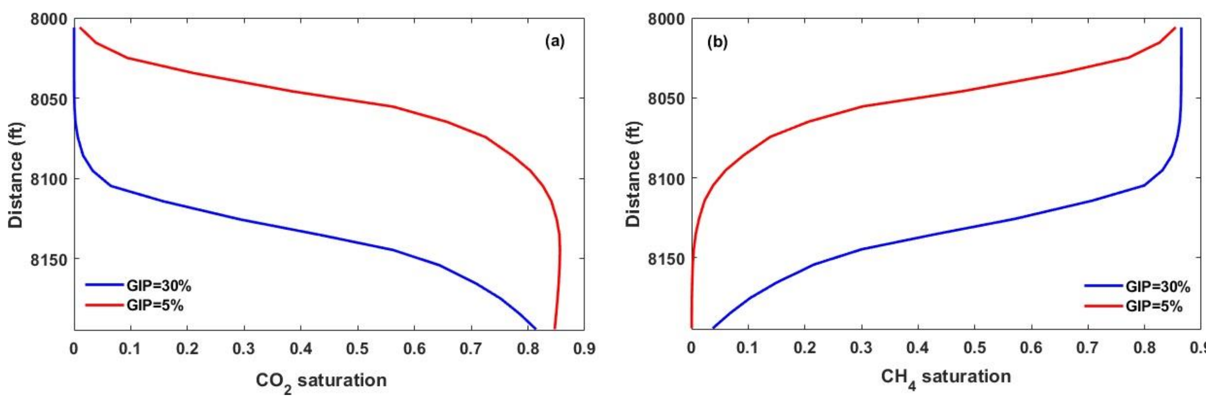


Figure 47: Profile of gas ([a] CO_2 and [b] CH_4) saturation along the reservoir depth at the end of the post-injection stage in the depleted reservoirs containing different remaining gas in place volumes.

3.3. Discussion

Simple reservoir modeling was performed to better understand the impact of residual gas (CH_4) on the CO_2 injected in a dry depleted gas reservoir. Simulation results suggest that the presence of the remaining gas does not negatively affect the CO_2 storage capacity of the reservoir, and the maximum pressure build-up obtained in the reservoir containing the highest volume of the remaining gas was far below the original reservoir pressure corresponding to the pre-production stage. It is observed that the CO_2 plume tends to migrate upward during the injection period, as its displacement is governed by gravity. As CO_2 is denser than the resident methane, it starts to recede and accumulate mainly at the bottom of the reservoir when injection stops, while the remaining gas (methane) fills the regions right below the reservoir top. At a higher volume of remaining GIP, the gas (methane) layer is thicker at the end of the post-injection stage, while a thinner layer of CO_2 plume forms at shallow depths. Thus, a depleted reservoir with a higher amount of remaining gas may provide better CO_2 storage integrity, as the formation of a thick gas cushion would decrease the risk of CO_2 migrating towards the top sealing layer in the post-injection stage. It is also found that the majority of the CO_2 plume remains mobile, with capillary-trapped CO_2 and then dissolved CO_2 accounting for the second-most and least abundant forms of CO_2 in the reservoir, respectively. We further observed that the amount of remaining GIP does not significantly affect the residual (capillary) and dissolution trapping efficiency of CO_2. To better engineer the residual and dissolution trapping of CO_2 in depleted gas reservoirs with no-flow boundaries, one solution could be water-alternative-CO_2 injection. The increased volume of water in the reservoir under such a solution would improve CO_2 capillary and dissolution trapping. However, the injection of water should be optimized to ensure it would not limit the storage capacity of the reservoir by filling the available pore space with an incompressible fluid (water).

4. Impact of Boundary Conditions and Pressure Depletion

4.1. Introduction

Depleted fields span a wide range of reservoir pressure states. Some, such as Forties, are well connected to the surrounding aquifers and are still hydrostatically pressured at the end of production (Babaei et al., 2014). Others, such as Altmark, K12-B and Lacq are bounded by sealing faults, with no connection to more regionally extensive aquifers. Post-production reservoir pressure in these fields may be as little as 10% of what it was at the time of discovery (Rebscher et al., 2006; Total, 2015; Vandeweijer et al., 2018). Between these extremes is a wide spectrum of fields (e.g. Naylor) with some aquifer connection and/or engineered pressure support during production (Cook, 2013). These fields experience some pressure drawdown during production but recover toward initial pressure over a period of months to years following production.

From the perspective of CO_2 storage, pressure is a key factor in determining storage capacity. Pressure build-up can limit both the sustainable injection rate and the ultimate field capacity. Excess pressure may trigger seismic events or open pre-existing fractures, which unless appropriately managed may create unacceptable risks to containment. Maximum allowable injection pressure is thus limited by the weakest element in the containment system, including the fracture strength of the caprock, the integrity of pre-existing wells and the critical strength of local faults (Eiken et al., 2011; Zoback and Gorelick, 2015; Ringrose and Meckel, 2019). The headroom between pre-injection reservoir pressure and the critical pressure limit thus represents both injection capacity and margin for safety. Indeed some screening criteria consider pressure depletion a positive (Raza et al., 2016). However, achieving significant pressure depletion depends on having limited or no connection to regional aquifers. In fields with good connection to a large aquifer, produced volumes are quickly replaced by formation waters, resulting in minimal pressure depletion. Similarly, injection into a field with good connection to a large aquifer spreads the injection-related impact, resulting in minimal and transitory pressure increase. By contrast, production from small, closed compartments may create significant pressure depletion but the volumetric impact of additional pressure space for injection is offset by the small compartment size. In this section, we look at the capacity trade-off between pressure-depleted fields with closed boundaries versus hydrostatically pressured fields with open boundaries.

4.2. EASiTool Modeling

To look at the high-level capacity implications of pressure depletion, we used EASiTool, a software package developed at the Gulf Coast Carbon Center expressly for estimating injection capacity and pressure build-up (Ganjdanesh and Hosseini, 2017, 2018). It offers a user-friendly analytical simulation toolbox for dynamic CO_2 storage capacity estimation. Published validation tests show that the results of EASiTool are within 30% of full numerical simulation, yet require only a fraction of the computational cost (Ganjdanesh and Hosseini, 2017, 2018). It is currently used by US government agencies and oil industry partners for screening, as it requires little time or field architecture data. That said, it is a quick-look tool—it uses a single set of reservoir properties and does not include the effect of dip or stratigraphic architecture.

Here, we created a generic model using typical Gulf of Mexico coastal reservoir parameters (Table 5). 20 MPa (2900 psi) represents hydrostatic pressure and 30 MPa was chosen as the maximum allowable pressure for all models. Injection was modeled for a 20-year period at a rate determined by the software to maximize capacity, such that model reservoir pressures would peak as close as possible to 30 MPa without exceeding that threshold. We looked at four scenarios:

- Reference case: Hydrostatic initial reservoir pressure (20 MPa; 2900 psi) and closed boundaries, representing a wet reservoir with no connection to a larger aquifer

- Pressure-depleted case: 10 MPa (1450 psi) initial reservoir pressure and closed boundaries, representing a post-production field with 50% pressure depletion
- Large aquifer case: Hydrostatic initial pressure and open boundaries, representing a post-production field with good aquifer connection and therefore no pressure depletion
- Comparison case: A hybrid model with hydrostatic initial pressure and open boundaries but limited injection, equal to the total injected mass in the pressure-depleted case.

While the binary choice of open or closed boundaries is simplistic, the results bracket the spectrum of possible boundary behaviors. The choice of 10 MPa (1450 psi) for a depleted reservoir pressure was governed by the largest differential between initial and maximum allowable reservoir pressures that EASiTool can handle. Real fields may show far greater drawdown but the smaller range is still sufficient to illustrate the relationship between ultimate storage capacity and initial pressure depletion.

Parameter	**Modeled value**
Initial reservoir pressure	Variable (10–20 MPa; 1450-2900 psi)
Reservoir temperature	65ºC
Reservoir thickness (m)	100 m
Reservoir fluid	100% saline brine
Aquifer salinity	2 moles/kg
Reservoir permeability	100 mD
Rock compressibility	$5x10^{-10}$/Pa
Maximum bottom-hole pressure	30 MPa (4351 psi)
Reservoir area	100 km^2
Simulation time	20 years
Injection well radius	0.1 m
Number of injection wells	16
Injected fluid	100% CO_2

Table 6: Modeled reservoir properties.

Results are shown in Figure 48 and summarized in Table 7, overleaf. While pressure depletion does indeed offer a significant increase in capacity over the base case, it doesn't come close to the capacity of a field with open boundaries and no initial pressure draw-down. Indeed, under the model parameters, the latter case offers a capacity around 10 times that of the pressure-depleted case, the result of being able to displace pore fluids out of the field. In both cases, injected CO_2 remains within the field boundaries and in that sense, the footprint of both is similar. In reservoir pressure terms, however, closed boundaries confine pressure changes to the field whereas open boundaries allow them to propagate more widely. In the model, with no stratigraphic or structural complexity, that distance is limited only by reservoir thickness and permeability. In practice, geologic architecture is likely to limit pressure propagation even with open boundaries on the field but the point remains that the pressure footprint is likely to exceed the field boundaries. In relatively isolated offshore projects like Sleipner, that increased footprint may not matter. In onshore projects, with neighbors and tightly demarcated lease lines, it may matter a great deal. In either case, the required Area of Review (AoR) would exceed the field boundaries (EPA, 2013). It is worth noting that that this larger AoR may increase the characterization costs, both because of the larger area and because it may increase the number of legacy wells needing review and possible remediation.

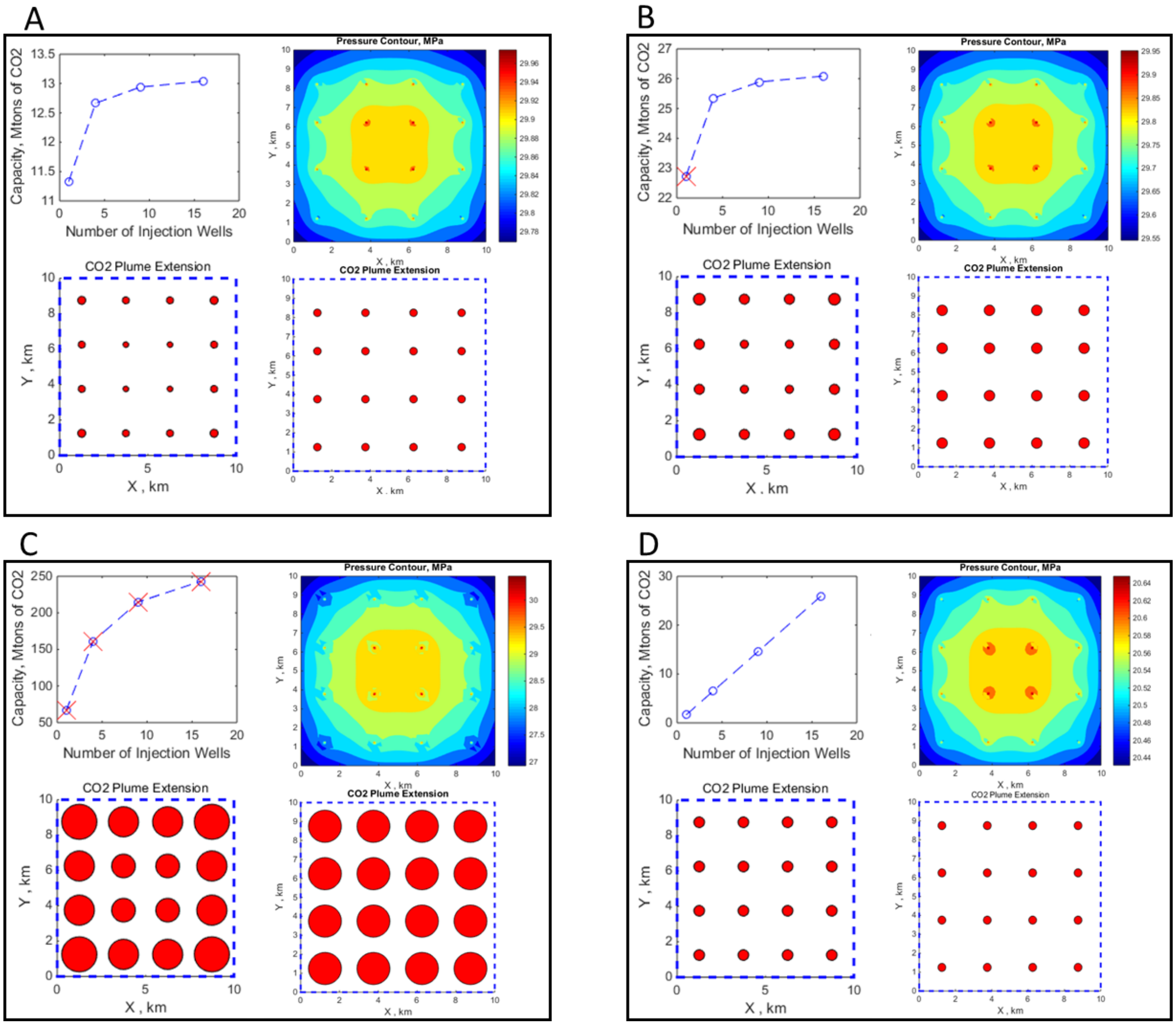


Figure 48: EASiTool model results with varying initial pressures and boundary conditions. Each box shows the results of two nearly equivalent scenarios. The top left panel in each box shows storage capacity as a function of the number of injectors where maximum pressure cannot exceed 30 MPa. Red Xs show wells denote injection rates greater than 2000 tons/day, which is not impossible but a flag to check assumptions. The bottom left panel in each box shows a map view of the resulting CO_2 plume spread. The top right panel in each box shows the maximum pressures in map view when every well injects at the same rate (rate chosen to give the same total storage over the 20-year model run). The bottom right panel in each box shows the map view plume spread with constant injection rate. Models are as follows: (A) Reference case—hydrostatic initial reservoir pressure (20 MPa) and closed boundaries, representing the case of a wet reservoir with no connection to a larger aquifer. Capacity is 13 Mt. (B) Pressure depleted—10 MPa initial reservoir pressure (50% of hydrostatic) and closed boundaries, representing the case of pressure-depleted field with no connection to a larger aquifer. Capacity is 26 Mt. (C) Open boundaries—hydrostatic initial reservoir pressure (20 MPa) and open boundaries, representing the case of a depleted field with good aquifer connection. Capacity is 248 Mt (and 273 if more wells are allowed). Note that although the CO_2 is confined to the field, the pressure impact spreads far beyond the field. (D) Limited injection—hydrostatic initial pressure, open boundaries and 26 Mt of CO_2 injected, divided equally among 16 wells. Capacity is equivalent to the pressure-depleted case (Model B) but the pressure build-up is less than 1 MPa, compared with almost 20 MPa in the pressure-depleted case with closed boundaries.

For comparison, we ran a final case in which open boundaries and hydrostatic initial pressure were paired with limited injection of 26 Mt, equal to the total capacity of the pressure-depleted case. Instead of a final reservoir pressure of 30 MPa (4351 psi), the comparison case peaked at 20.64 MPa (2993 psi), an increase of less than 1 MPa (145 psi). That may be small enough to remain under the threshold pressure increase that would trigger evaluation of legacy well integrity (EPA, 2013). Depending on the proximity of neighboring injection, such a project might safely and economically operate even in an area with dense legacy well clusters.

Model	**Boundary condition**	**Initial pressure**	**Final pressure**	**Capacity (Mt)**
Reference case	Closed	20 MPa (2900 psi)	30 MPa (4351 psi)	13
Pressure depleted case	Closed	10 MPa (1450 psi)	30 MPa (4351 psi)	26
Large aquifer case	Open	20 MPa (2900 psi)	30 MPa (4351 psi)	248 (273 if more wells are allowed)
Comparison case	Open	20 MPa (2900 psi)	20.6 MPa (2988 psi)	26 (specified limit)

Table 7: Summary of model results.

4.3. CMG Modeling

To further investigate the effect of pressure depletion on the CO_2 storage capacity, we used compositional reservoir simulations of CO_2 injection into a depleted gas reservoir with closed boundaries and depleted pressure of $1.58\ \mathrm{MPa}$ $(230\ \mathrm{psi})$. Reservoir and fluid properties are the same as what we considered for the offshore Texas model generated in the previous section on residual gas. To reach the depletion stage prior to the CO_2 injection, we conducted a production simulation up to a recovery factor of 95% (GIP=5%). The simulation setup for the depletion simulations is the same as the one explained in the previous section. CO_2 is injected through a single well into the formation with a maximum well bottom-hole pressure of $44\ \mathrm{MPa}$ (6400 psi), selected according to the rock fracture pressure. The injector is located in the center of the domain with the perforation length of $9\ \mathrm{m}$ $(30\ \mathrm{ft})$. The injection rate is selected as $1 \times 10^6\ \frac{\mathrm{m}^3}{\mathrm{day}}$ $(36\ \frac{\mathrm{Mscf}}{\mathrm{day}})$, which is set as the well's constraint in the injection simulations. CO_2 injection occurred for 50 years. Figure 49 represents the evolution of reservoir pressure build-up as a function of the cumulative volume of stored CO_2 during its storage in the depleted gas reservoir with GIP=5%. According to the simulation results, we reach the maximum admissible bottom-hole injection pressure of $44\ \mathrm{MPa}$ $(6400\ \mathrm{psi})$ at the year 2063, equivalent to 41 years of injection. Figure 50 represents the time evolution of CO_2 density and its cumulative volume during the injection period. We observe that the maximum volume of stored CO_2 is achieved at the year 2063 when the injection stopped to avoid exceeding the maximum allowable reservoir pressure. According to the results, CO_2 density keeps increasing as the pressure builds during injection. At the early stage of the injection, CO_2 is in the gas phase due to the very small reservoir pressure. As the injection proceeds, CO_2 changes phase from gas to supercritical. To better understand the onset of the CO_2 phase transition, we have shown (Figure 51) how CO_2 density varies with pressure at the temperature of $353\ \mathrm{K}$ $(176\ \mathrm{F})$, which is the reservoir temperature in this study. The data shown in Figure 51 is taken from the NIST Standard Reference Database. It is observed that the phase transition occurs at the pressure of $7.4\ \mathrm{MPa}$ $(1073\ \mathrm{psi})$. According to these observations, it can be inferred that the extreme pressure draw-down in the depleted gas reservoirs may provide the condition suitable for the injection of gas-phase CO_2 into these reservoirs.

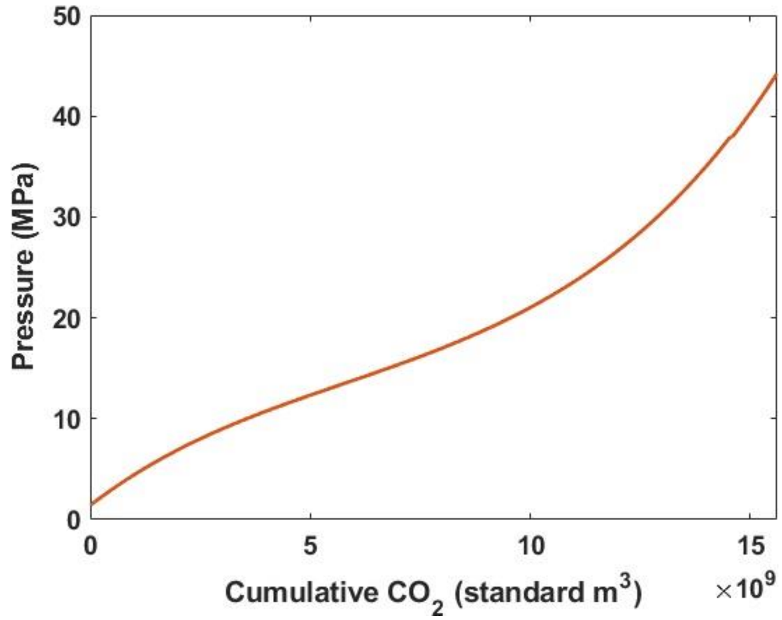


Figure 49: Evolution of reservoir pressure as a function of cumulative volume of stored CO_2 in the depleted gas reservoir with GIP=5% during the injection period. The injection was conducted for 50 years. The injection rate is set at $1 \times 10^6 \frac{m^3}{day}$ ($36 \frac{Mscf}{day}$). For reference, $5x10^9$ m^3 of CO_2 at STP is 9.9Mt.

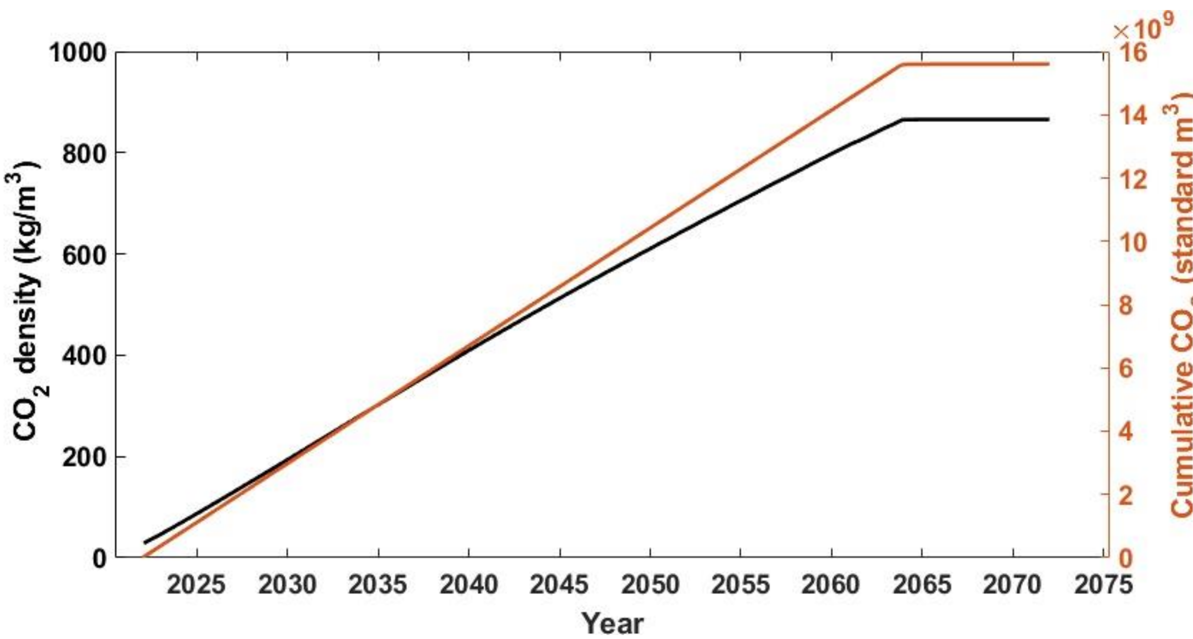


Figure 50: Time evolution of CO_2 density and its cumulative stored volume in the depleted reservoir with GIP=5% during the injection period. The injection was conducted for 50 years. The injection rate is set at $1 \times 10^6 \frac{m^3}{day}$ ($36 \frac{Mscf}{day}$).

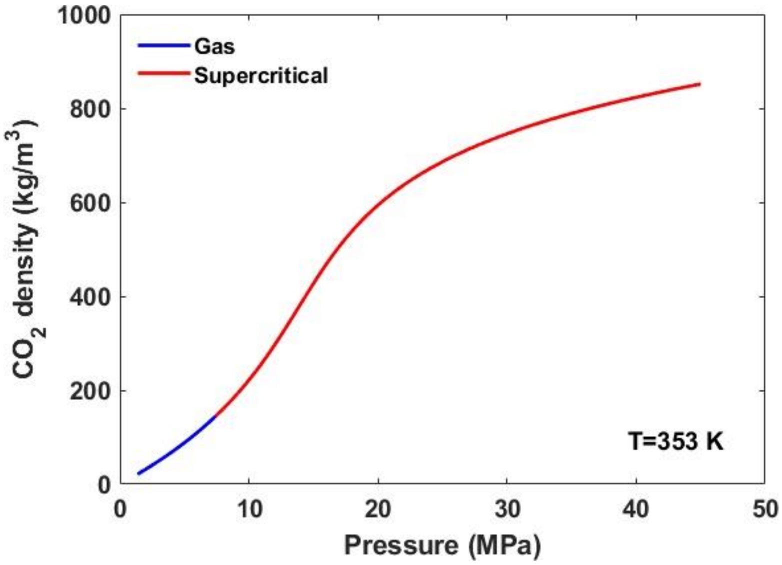


Figure 51: CO_2 density as a function pressure at $T = 353\ K\ (176\ F)$. Data is taken from the NIST Standard Reference Database.

4.4. Discussion

In the scenarios modeled here, maximizing capacity and/or limiting reservoir pressure build-up for a given injection volume clearly favor fields with open boundaries. These boundaries allow the displacement of pore fluids and the dispersion of injection-related pressure build-up far beyond the field boundaries. The result is a CO_2 storage capacity many times what is achievable in a similar field with closed boundaries. Although our choice of software limited pressure depletion to 50% of hydrostatic, we note that capacity in the closed boundary case is very close to a linear function of the available pressure space. Even with an initial pressure near zero, closed boundaries offer far less capacity than open ones. As noted however, open boundaries facilitate larger capacity by allowing propagation of pressure beyond the field boundaries, even if the CO_2 remains within them, as modeled here. Pressure propagation creates a larger Area of Review (AoR) that may impact neighboring storage projects if they are close enough and/or increase the cost of characterization. Whether these trade-offs make business sense likely depends on the density and proximity of neighboring fields and/or storage projects. Even with closed boundaries, the CMG modeling shows that a depleted field may offer significant storage capacity that is perfectly adequate for many projects.

Besides simply maximizing capacity, there are other pressure-related considerations beyond the scope of modeling that may impact the choice of fields. For example, closed boundaries offer a project with a clear footprint and therefore tightly defined leasing and monitoring requirements that may reduce costs compared to a larger area. Additionally, starting with a pressure-depleted reservoir offers historically proven containment security if post-injection reservoir pressure is limited to the value at the time of field discovery (virgin pressure). Even greater containment security is available if reservoir pressure is limited to less than hydrostatic, as this creates a pressure barrier to leakage in addition to the geologic barriers. For projects with limited capacity needs, close neighbors, and/or a string of depleted fields to tap, these considerations may weigh more heavily than pure capacity.

Pressure-depleted fields may also offer challenges not found in fields with good aquifer connection. First, the process of pressure depletion creates the opportunity for reservoir compaction and loss of pore space that cannot be regained with injection. Capacity reduction and compromised infrastructure integrity are both possible. In some cases, stress arching protects depleted fields from compaction (Orlic, 2016). Fields like Ekofisk and Wilmington represent the other end of the spectrum, with significant loss of pore space and overlying subsidence on the order of 10 m. Although compaction adds reservoir energy and aids in hydrocarbon recovery, it is a decided negative for storage. The irreversible loss of pore space reduces storage capacity and attendant reservoir deformation can be enough to shear well casings and crack overlying pipelines (Nagel, 2001).

The second key challenge of severely pressure-depleted reservoirs is dealing with the Joule–Thompson effects of pressure changes between wellhead and reservoir. As the CMG modeling presented here illustrates, extreme pressure depletion may create conditions for early storage of CO_2 in a gas phase. Expansion of CO_2 as it exits the wellbore may result in formation of ice and/or hydrates that can block the well or degrade reservoir permeability and therefore injectivity. The thermal stress created by rapid CO_2 expansion might also be enough to fracture the well casing and potentially lose containment integrity. Similarly, the thermal stress may create fractures in the seal with potential adverse effects on containment (Preisig and Prévost, 2011; Gor and Prévost, 2013; Gor et al., 2013). Last, compression and heating of CO_2 at the wellhead may result in evaporation, rapid expansion, over-pressurization and backflow into the injection system (Sacconi and Mahgerefteh, 2020). These risks can be managed with downhole flow control devices and careful start-up, but they add to the expense, risk and operational complexity of a project (Hughes, 2009; Sacconi and Mahgerefteh, 2020).

There is of course an entire spectrum of boundary conditions between the end-member open and closed boundaries modeled here. Real fields often have semi-permeable boundaries that can support temporary pressure differences that may take anywhere from months to millions of years to equilibrate, depending on the details of the boundaries (Muggeridge et al., 2004, 2005). In CCS, perhaps the clearest example comes from Phase 1 of the Otway Project. In that case, gas production resulted in a reservoir pressure drop from 19.6 MPa (2842 psi) at the time of discovery to 11.9 MPa (1726 psi) at the time of abandonment, 20 months later. By the time it was logged again, 32 months post-production, reservoir pressure had recovered to 17.4 MPa (2524 psi) (Underschultz et al., 2011; Cook, 2014). A similar example comes from the Esmond gas field in the UK North Sea. Virgin pressure at the top of the upper reservoir sand was measured at 15.7 MPa (2277 psi) and ~14 MPa (2030 psi) in the lower sand, with a 7-m mudstone separating the two sands. At the end of production, 10 years later, pressure in both sands were down to ~1 MPa (145 psi). An appraisal well drilled 13 years post-production showed that pressure in the lower reservoir had recovered to ~12 MPa (1740 psi) while the upper one remained at ~1 MPa (145 psi) (Bentham et al., 2017). Both of these cases indicate connection to a larger aquifer that is insufficient to instantaneously replace produced gas but that can do so on human timescales (i.e., years to decades). At Naylor, that semi-permeable boundary appears to come from gaps in the fault network surrounding the field (Cook, 2014). At Esmond, it seems to be a simple function of reservoir thickness and permeability with small fault baffles (Bentham et al., 2017).

Last, there is also a spectrum of operational models for injection that seek to take advantage of the security of depleted fields with closed boundaries but avoid the risks associated with injection into extremely pressure-depleted reservoirs. In general, these models don't wait for the end of production to begin injection but rather seek some balance between injection and production. Most such models would probably be considered EOR/EGR but in principle, they could include pure storage schemes, like Snøhvit that injects into the water leg of a field (White et al., 2018; González-Nicolás et al., 2019). In the best cases, these scenarios might create higher hydrocarbon recovery, simultaneous revenue streams from both production and storage, and avoid the risks of start-up injection into very low-pressure reservoirs. In practice, it may be difficult to keep injected CO_2 away from production wells, which would negatively impact either sequestration (if the produced CO_2 were vented to the atmosphere) or project economics (if produced CO_2 were separated and reinjected). In the case of oil reservoirs, the higher value of oil and the relative ease of separating it from CO_2 may justify the added expense. For gas, it is often a harder case to make.

4.5. Conclusion

Closed reservoir boundaries create the opportunity for post-production reservoir pressures well below hydrostatic. That creates potential security for storage operations in that they can operate in proven pressure space (limiting the post-injection reservoir pressure to its proven pre-production value) and be assured that CO_2 and injection-related pressure will remain laterally confined within the boundaries of the field. On the other hand, closed boundaries limit the ability to dissipate pressure build-up and therefore offer more restrictive storage capacities. Simple models indicate that a hydrostatically-pressured field with open boundaries may offer ten times the capacity of a similar field with closed boundaries, even if reservoir pressure is initially 50% lower.

Real fields often have semi-closed boundaries, which introduces a time component to the evaluation. In such cases, there may be a limited time available for storage operations to take advantage of post-production pressure draw-down. Similarly, injection-related pressure build-up may be slower and will dissipate with time. Injection into highly pressure-depleted fields carries operational challenges and may require special completions to avoid adverse events such as formation of water ice or precipitation of salts in the near-wellbore reservoir.

5. Economics of Infrastructure Reuse

5.1. Introduction

This analysis looked to accomplish this goal by developing a standardized framework to assess the costs to deploy a carbon capture and sequestration project that would sequester 1 million metric tons of CO_2 per annum (Mtpa) over a 25-year active injection period[1] in a depleted oil and gas field, with a total project life of 45 years. Thus, the economic models describe a project that sequesters 25 million metric tons of CO_2 total and continues to monitor the sequestered CO_2 for 20 years after the project ceases to operate. This analysis developed four scenarios to accomplish the same aforementioned goal; (1) using new onshore infrastructure, (2) the reuse of existing onshore infrastructure, (3) new offshore infrastructure, and finally (4) the reuse of existing offshore infrastructure (Ringrose and Meckel, 2019). Each of the cases were analyzed for their costs and an uncertainty analysis was utilized to develop ranges for uncertainties in both capital costs and overall performances, including contingencies for the failure of existing infrastructure during reuse.

The analysis was restricted to more conventional techniques and did not consider horizontal drilling and hydraulic fracturing techniques. Given that the sector is relatively young, there are likely plenty of less complicated and more conducive locations to consider before moving to harder geologies such as shales. The analysis also assumes that CO_2 will be delivered to the injection site at injection pressure (at least 100 bar or 1450 psi, dense phase) and thus will not require any additional compression equipment on-site. For this analysis it is assumed that 50 km of pipeline will be either built or reused. All costs have been converted to 2020-USD values.

Because the purpose of this analysis is to assess the costs of new vs. reuse of existing infrastructure, the following sections will focus on CAPEX of major components and not OPEX as it is assumed that OPEX would be similar for new infrastructure and upgraded/reconditioned existing infrastructure. Also, any given project will likely require a significant amount of engineering and project management which is not captured here.

Both on- and offshore infrastructure assessments are fraught with uncertainties[2]. While the cost to drill onshore wells is relatively well-known, especially given the maturity of the EOR sector, uncertainty can be found in the state of existing wells and the capacity of pipelines to perform as needed. For offshore projects, less is known about all aspects of the system given the relative immaturity of the offshore EOR sector and the smaller number of offshore wells in general. The literature indicates that, like onshore, it is easier to estimate the costs of drilling wells than it is to estimate their supporting infrastructure.

5.2. New onshore infrastructure

The basic requirements for a new greenfield type site for CCS are relatively simple in concept, but at least in the US will still be subject to most of the EPA class VI UIC requirements for new wells. The essential parts of the deployment are roughly categorized in just a few major components: drilling pad and road work, well drilling and completion, and the pipeline as well as other auxiliary infrastructure needed to move and manage CO_2 to the sequestration site. The costs for each of these categories will vary widely

[1] Ringrose & Meckel, 2019.

[2] Re-Use of Oil & Gas Facilities for CO_2 transport and Storage, 2018/06, July, 2018.

depending on the location and access to the site, i.e. if bridges are needed in the roadwork or long stretches of pipeline are needed to move CO_2.

The advantages to using a new greenfield site include the ability to build infrastructure purposely designed for the CCS project and more flexibility in optimizing injection well locations to better take advantage of the characteristics of the receiving formation. While much has been learned about the injection and management from enhanced oil recovery (EOR) projects, some CCS project aspects will differ. For example, while EOR CO_2 injection wells are designed to drive hydrocarbons toward production wells, CCS injection wells will likely be best spaced much further apart so that they do not communicate with each other and limit the superposition of (higher) pressure perturbations. Thus, it might be difficult to deploy multiple wells from the same pad, which, depending on the characteristics of the receiving formation and the desired sequestration rate, might necessitate drilling in multiple locations.

The amount of infrastructure needed will very much depend on how much CO_2 each well can sequester, which is a function of the characteristics of the receiving formation. This analysis assumes that the average injection well will be able to sequester about 0.57 Mtpa of CO_2 (Ringrose and Meckel, 2019), and thus will require at least two wells and the supporting infrastructure.

5.2.1. Drilling pad and road work

This analysis assumes that two injection wells are needed, each with their own drilling pad and road access. However, the costs for the drilling pads are expected to be low as the techniques considered in this analysis are conventional in nature and highly-engineered “super-pads” are unlikely to be necessary. It is assumed that a small pad, on the order of 6,000 m^2 (~1.5 acres) will be sufficient. Pad costs are assumed to be roughly US $25,000 per pad (US $5000 for land grading and US $20,000 for a gravel base)[3]. An additional US $20,000 is estimated for 3.2 km (2 mile) of new dirt service road needed per pad (USDA Forest Service Northern Region Engineering, 2020). Thus, we estimate that roughly US $90,000 (US $72k–$108k) would be needed for new drilling pad and road access for a 1 Mtpa greenfield onshore CCS project.

5.2.2. Well drilling and equipment

The average costs to drill and complete new injection wells were taken from an EIA analysis of thousands of US oil and gas projects (EIA, 2016). While the EIA analysis had a high unconventional resource focus, it broke down the costs for drilling and completing a well into steps. This analysis assumed that the industry standard vertical drilling costs in the EIA study would easily transfer to CCS applications[4]. We estimate that new on-shore injector wells (just rig-related and casing costs, no frack completions) cost between US $1.9M–$2.9M depending on location, market conditions, rig day rates, and costs of steel and concrete (EIA, 2016). Because we assume that CO_2 arrives at the well site at injections pressure, we estimate that only about US $70,000 worth of on-site, permanent equipment would be needed during the injection period (EPA, 2008). This analysis assumed that one monitoring well would also be drilled for every injection well and that the costs for injection and monitoring wells would be similar (ZEP and IEAGHG,

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[3] Prices assumed based on basic land grading costs.

[4] The unconventional wells in the EIA analysis are similar in depth to a CCS well (which is a critical component of cost) and, at least initially, CCS wells are also likely to be located in well-known basins where the shallow geology is well known and drilling is routine. Also, high levels of CCS will likely require a high number of wells and such drilling could become very routine and could be reasonably be expected to approach the same sort of cost as unconventional wells without the completions and horizontal sections.

2010). Thus, we estimate that roughly US $10 (US $8M–$12M) would be needed for new injection and monitoring wells for a 1 Mtpa greenfield onshore CCS project.

5.2.3. Pipeline

Pipelines are often used to move CO_2 from source to sink. This analysis is agnostic as to the source, but will consider the pipeline needed to transmit the CO_2 to the injection site. This analysis will also assume that any dehydration of the CO_2 stream has taken place at the source and thus we will also not consider that equipment here. Because this section of the analysis is assessing new infrastructure, we will also assume that the pipeline segments are specified to include crack arrestors as part of their design (thicker wall sections at joints). This might not be the case if reusing an existing natural gas pipeline, but that will be discussed later. This section will then focus on the pipeline itself.

A review of the size and conveyance capacity of CO_2 pipelines indicated that a pipeline with a 250 mm (~10 inch) diameter would be sufficient to convey approximately 1 Mtpa of CO_2 to the injection site[5] (IEAGHG, 2014). It is assumed that a pipeline of this size and length would not need any booster stations, as per NETL study guidance. Thus, this analysis estimates that a 1 Mtpa CO_2 pipeline would cost about US $576,000/km with a range of US $386,000/km to $767,000/km, highly dependent on the terrain. Thus, we estimate that 50 km of such pipeline would cost US $30M (US $20.1M–$39.9M).

5.2.4. Other auxiliary infrastructure

Other infrastructure, such as well remote head monitoring equipment are expected to be small and not considered in this analysis.

5.2.5. Total new onshore infrastructure up-front costs

Summing up the above categories indicates that the major up-front capital costs of a new onshore CCS project with the ability to sequester 1 Mtpa, including 50 km of pipeline infrastructure, would be about US $40M, with a range of between US $28.1M and US $51.9M. Figure 52 shows a sensitivity analysis around four of the major costs assumptions for new onshore CCS projects on total overall project CAPEX. Beyond the above stated ranges of well costs and pipeline lengths, we also performed a sensitivity around the length of pipeline and well injection capacity, each at plus or minus 20%, thus a pipeline length of 40-60 km and a will injection capacity of 0.46-0.68 Mtpa.

[5] This is assumed based on calculating the diameter for roughly ½ the volume of the 2 Mtpa Weyburn CO_2 pipeline as described in "CO_2 Pipeline Infrastructure" IEAGHG, 2013.

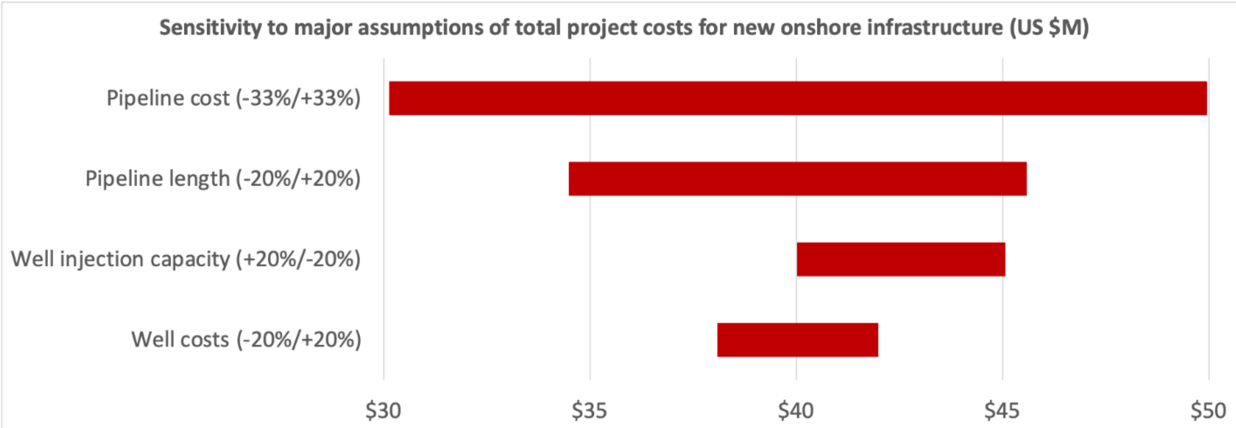

Figure 52: Sensitivity to cost assumptions for new onshore CCS infrastructure (US $M).

5.3. Reuse of onshore infrastructure

This section discusses the implications for reusing on-shore infrastructure for CCS projects. This analysis will take a similar approach as the new onshore infrastructure and will seek to provide an estimate of the costs of deploying a 1 Mtpa CCS project through the reuse of existing infrastructure in a depleted oil and gas field. This analysis will assume that the existing field has 100 existing plugged and abandoned (P&A) wells as well as natural gas pipeline access. This analysis will assume that the wells in the depleted fields were completed using modern completion standards that came about in the 1950s and 1960s (Technology Subgroup of National Petroleum Council (NPC), 2011). Because wells abandoned before modern standards were enforced have the potential to perform poorly (little or no concrete in their abandonments), this analysis cautions against considering such areas for CCS projects.

5.3.1. Drilling pad and road work

The ability to reuse existing drilling pads will depend on how long they have been abandoned. Fields that have been reused for other activities such as farming or grazing might need the pads to be fully rebuilt whereas recent production wells might have fully intact and useable pads. Thus, like in the greenfield case we estimate that roughly US $0 to $90,000 (US $0–$108k) would be needed to recondition drilling pads and road access for the project.

5.3.2. Wellfield assessment

Studies indicate that only looking at the records of abandoned oil and gas fields will underestimate the number of wells at a given site (Saint-Vincent et al., 2020). Thus, this analysis assumes that an aerial magnetic survey would be necessary to identify all existing wells in an area, at an estimated cost of about US $129k (US $103k–$155k). Furthermore, it is estimated that pulling and compiling existing records might take on the order of 6 person-hours per well, for an estimated total project cost of about US $90k (US $72k–$108k).

5.3.3. Well drilling and equipment

We assume the same needs for injection and monitoring wells as the greenfield site. This analysis further assumed that about 10% of existing wells would have incomplete or missing records and would require reentry to verify their integrity. It was further assumed that about 1% of existing wells would need major reworking[6]. The actual number of wells that will need reworking will be very site-specific. Likely the older the existing field, the more remediation that will be necessary.

5.3.4. Injection and monitoring wells

Recent reports indicate that converting existing wells into injection and monitoring wells costs about 60% of the cost of a new well (ZEP and IEAGHG, 2010). Thus, we estimate that cost to be about US $1.16M–$1.74M per well depending on prevailing market factors and location. This analysis estimates that (including new wellhead equipment), it would cost about US $7.4M (US $5.9M–$8.9M) to convert four existing wells into the needed injection and monitoring wells[7].

5.3.5. Existing well remediation

Internal estimates (and direct experience) from the University of Texas' Bureau of Economic Geology indicate that reentering a previously "P&Aed" well to verify incomplete, suspect, or missing records costs on the order of about US $250k per well, with costs approaching $1M if significant structural problems are found. Data are sparse, but for the sake of this analysis we estimate that about 10% of existing wells would need to be assessed and about 1% would require major remediation. Thus, we estimate that it would costs between US $2.1M and US $4.9M to verify and fix any existing well issues.

5.3.6. Pipeline

Reusing existing natural gas pipelines for CO_2 transport is complicated. Natural gas pipelines often operate, and are presumably engineered for, lower pressures than needed for keeping CO_2 in a critical dense state. Natural gas pipelines often operate at pressures between 13 and 103 bar while supercritical CO_2 should be transmitted between 82 to 150 bar. Thus, while there is some overlap, at the very least, a repurposed natural gas pipeline will likely need additional booster stations and/or additional at-well compression equipment to keep the CO_2 at supercritical and injection pressures. It is possible to transmit the CO_2 in a gaseous phase at lower pressures that are closer to natural gas line pressures, and, if the depleted field were of sufficient size that the pipeline diameter were large enough to handle the volumes of CO_2, it could be possible to reuse the existing pipeline.

Given the assumption of an existing pipeline that previously carried natural gas away from the field, there are roughly three options given the characteristics of the pipeline itself; (1) reuse the pipeline if it can handle the needed pressures, however, it will likely require additional pressure booster station(s) either along the pipeline or at the injection well, (2) transmit the CO_2 at a lower pressure, in a gaseous form, if the pipeline is of sufficient diameter for the flowrates desired, or (3) replace the existing pipeline in the same right-of-way with a new one suitable for the desired flowrates and pressures.

For the first option, assuming that an existing natural gas pipeline could deliver 1 Mtpa of CO_2 at roughly 100 bar, the analysis estimates that an additional booster pump would be required and would cost about US $1.1M (US $0.9M–$1.3M). If the existing pipeline were able to deliver 1 Mtpa of CO_2 at a lower pressure (~ 50 bar, gaseous form, bigger pipeline diameter), the booster pump would need to be roughly twice as large and cost about US $2.2M (US $1.8M–$2.6M). If the existing pipeline is of insufficient size or pressure to allow for just a relatively simple booster pump retrofit, we estimated that the existing pipeline could be replaced for roughly the same cost of a new purpose-built pipeline, minus the cost to acquire

[6] Estimate developed with discussions at the University of Texas Bureau of Economic Geology.

[7] This assumes the same 0.57 Mtpa well storage capacity as in the greenfield assessment.

the right-of-way, assuming it were sufficient for the new pipeline. We estimate this pipeline replacement to cost about US $28.3M (US $19M–$37.6M).

5.3.7. Other auxiliary infrastructure

Other infrastructure, such as well remote head monitoring equipment are expected to be small and not considered in this analysis.

5.3.8. Total infrastructure up-front costs for onshore reuse

The pipeline is a major expense for the entire project, constituting roughly 75% of the estimated up-front costs for the project. If pipeline options 1 or 2 were available for a project, it would likely cost less than the greenfield assessment[8], estimated at US $12.3M (US $9.1M–$15.5M) and $13.4M (US $10M–$16.8M), respectively. However, if a suitable pipeline were not available that could satisfy option 1 or 2, we estimate that replacing the pipeline would increase the overall project costs to about US $39.5M. Figure 53 shows a sensitivity to major assumptions in the analysis on total project costs, assuming that the project was able to reuse an existing pipeline, but needed upgraded additional compression on-site (the above option #2).

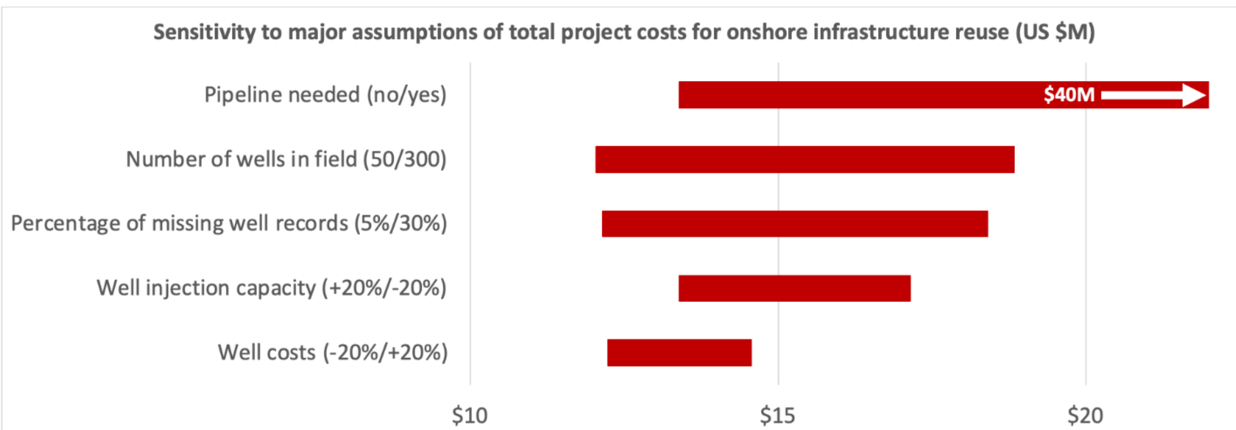

Figure 53: Sensitivity to cost assumptions for reuse of existing O&G infrastructure for onshore CCS (US $M). Note that "Number of wells in field" and "Percentage of missing well records" replace the number used in the model with the lower/higher numbers show whereas the other categories show a percent change from the assumed value used.

5.4. Comparison of new and reuse for onshore CCS infrastructure

If a suitable pipeline exists that can be reused to send CO_2 to the injection site, it might be cost-optimal to reuse an existing field even with the liabilities associated with existing wells. However, if a new pipeline must be constructed or rebuilt, the costs for both green and brownfield sites are essentially the same, US $40M vs. US $39.5M, respectfully (both highly dependent on local conditions). Thus, the major deciding factor between the two choices is likely the integrity of the existing wells. However, while not considered directly in this analysis, other factors, such as location, ownership, stakeholder relations, etc. could also be pivotal when comparing sites to each other. It is also worth noting that hydrocarbon production wells

[8] This holds for even higher percentages of faulty wells. In fact, if we assumed that 100% of the wells needed to be reentered and up to 10% needed major renovation (at our estimated costs), the cost is only slightly higher than the original assumptions (10%/1%) and a new pipeline.

may not be ideally located for CO_2 injection. At this stage of sector maturity, each effort will probably need project-specific evaluation.

5.5. Offshore infrastructure

The next sections will be similar to the previous but will consider the tradeoffs and costs of new vs. the reuse of offshore oil and gas infrastructure for CCS projects. Estimating costs for offshore infrastructure is difficult as fewer offshore investments have been made in recent years as many US producers have shifted to onshore shale production. And, while onshore CCS costs can be extrapolated from EOR methods, we are only aware on one operating offshore EOR project in Brazil (Eide et al., 2019) and a handful of other offshore carbon sequestration projects.

5.6. New offshore infrastructure

Offshore infrastructure for CCS projects will generally fall into the same major cost bins: platform, drilling and completing, and CO_2 pipeline, but each are generally more expensive than their onshore counterparts. This section will borrow some assumptions from the previous sections, such as injection well capacity, but will deviate from others, such as requiring each well to have its own platform.

5.6.1. New offshore platform

By their very nature of having to suspend the well working surface above the ocean's saltwater, offshore drilling platforms are much more expensive than their relatively simple onshore counterparts. Benchmarking costs for such projects has proven to be difficult and because of their higher costs are often specially designed for place and purpose (EIA, 2016). However, this analysis will assume that new offshore CCS projects would be located in relatively shallow waters and utilize the compact Wellhead on a Stick (WOS) monotower design (Jansen et al., 2011), which, admittedly might not work in all locations and is thus likely on the lower cost side. Taking values from Jansen et al, we estimate that this type of platform would cost about US $66.4M (US $46.5M–$86.4M) to install.

5.6.2. Drilling and completing new offshore wells

Offshore drilling costs vary more widely than onshore costs and depend on many factors, including water depth, drilling ship daily rates and other prevailing market conditions. We estimated that, in our base case assumption, two injection wells would be drilled along with just one monitoring well to reduce overall costs. Based on data from Jansen et al. and the US Energy Information Administration (Jansen et al., 2011; EIA, 2016), we estimate that drilling three offshore wells would cost roughly US $152M (US $106.5M–$197.6M).

5.6.3. New offshore pipeline

Under most conditions, offshore pipelines are more expensive than onshore pipelines. The IEAGHG (IEAGHG, 2014) estimates that offshore pipelines are as much as seven times more expensive than their offshore counterparts , which also aligns with other estimates (ZEP and IEAGHG, 2010). From these sources, we estimate that a 50-km offshore CO_2 pipeline would cost about US $180M (US $120.5M–$239.2M).

5.6.4 .Total up-front cost estimate for new offshore infrastructure

Cost structures are vastly different between on and off shore projects. Offshore cost breakdowns are more evenly distributed between each category than onshore—17% platform, 38% wells, and 45% pipeline costs (vs. 0.2% site-preparation, 25% wells, and 75% pipeline for onshore). We also estimate that the totals for new offshore infrastructure are roughly ten times higher than onshore and would cost about US $400M (US $273.5M–$523.2M). Figure 54 shows a sensitivity to different costs and capacities used in this analysis.

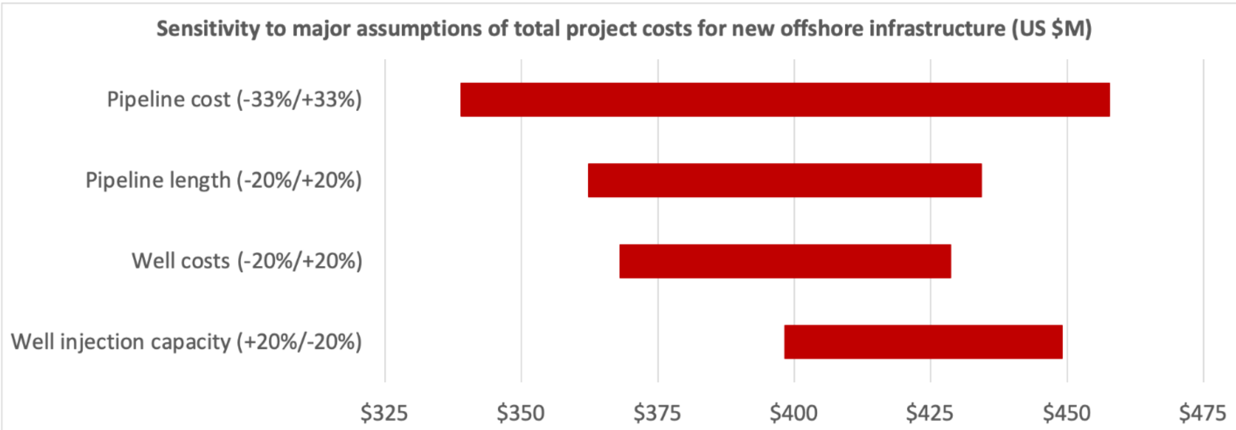

Figure 54: Sensitivity to cost assumptions for new offshore CCS infrastructure (US $M).

5.7. Reuse of offshore infrastructure

Many analyses have postulated that significant cost savings in CCS projects could be realized through the reuse of existing O&G extraction infrastructure. However, few projects have tested this hypothesis. It is also not the case that all existing infrastructure has the potential to be equally useful. A recent review of projects by the British government indicated that pipelines were likely to be the most useful infrastructure to reuse and other aspects, such as platforms and wells, might have very limited reuses (Department for Business, Energy & Industrial Strategy, 2019). Other considerations include the location of the CO_2 source, which, if far away from existing sequestration infrastructure, would likely drive up project costs.

This section will attempt to assess the implications for the reuse of offshore O&G infrastructure for carbon sequestration. This analysis assumes that, due to the complexity and costs of drilling offshore wells, the locations and conditions of existing offshore wells are more well-known and extensive surveys and existing well integrity checks are less needed than for onshore. However, of all the cases considered here, this case appears to have the least amount of data available for consideration.

5.7.1. Reuse of offshore platform

Not all offshore platforms will be conducive for reuse. Jensen et al. suggests that only the larger size platforms will have enough room for the necessary modifications and, unlike for the new infrastructure case, the smaller WOS-style platforms will be insufficient for such operations. However, this assumption might depend on the qualities of the pipeline being considered for reuse. Jansen et al. (2011) assumes that large heating equipment will be necessary for injection operations, however, this assumption is not found elsewhere and might be an artifact of the specifically proposed technology and thus, it might be possible to use other types of platforms if the on-site injection technology will fit on the space available.

It is possible that switching offshore platforms from hydrocarbon extraction to CO_2 injection and monitoring will require using platforms beyond their original stated lifetimes. Engineering analyses of previously proposed projects indicated that extending some platforms beyond their scheduled lifetimes and even adding additional weight to the structure would be feasible (Shell U.K. Limited, 2016). However, each considered offshore infrastructure reuse project would need to assess the feasibility of the platform on a case-by-case basis.

Assuming that platforms are usefully located, cost assumptions range widely for their reuse, with estimates ranging from approximately US $30M (Jansen et al., 2011) to $90M, with the simple average of these being similar to our estimated costs for a new platform.

5.7.2. Reuse of existing offshore wells

The potential exists for existing offshore wells to be reused for CO_2 injection, but challenges do exist, e.g., the wells might not be in the optimal location(s). We also assume that existing offshore wells have much better documentation than onshore and less exploratory evaluations will be necessary. However, workovers have the potential to be cheaper than new offshore wells. Based on costs estimates for the Shell Peterhead project (Shell U.K. Limited, 2016), we estimate that repurposing two injection and one monitoring well would cost about US $72.8M (US $51.1–$94.6).

5.7.3. Reuse of existing offshore pipelines

Offshore pipelines have been identified as one of the more promising aspects of existing infrastructure to reuse for CO_2 sequestration projects (Department for Business, Energy & Industrial Strategy, 2019). However, some of the same considerations exist for the reuse of onshore pipelines, namely its operational state and pressure tolerances. If the pipeline is only able to convey CO_2 at lower than injection pressures, pressure boosting pumps might be needed to raise the CO_2 to injection pressure, which might require significant amounts of energy at the platform. If it were not practical to have such levels of on-site energy, a new purpose-built pipeline might be necessary. This analysis has assumed a certain injection pressure, but injection procedures and component designs might be altered to incorporate such high-value assets, such as existing pipelines. Given these project-specific uncertainties, we will estimate that using an existing pipeline will cost between US $0 (in the case of a reuse with no modification) up to the cost of a new pipeline (the point at which investment in reuse no longer makes sense) and the cost of a new 50-km pipeline, or US $180M.

5.7.4. Total up-front cost estimate for offshore infrastructure reuse

Given the larger set of unknowns regarding offshore O&G infrastructure in general, it is difficult to make estimates on its ability to be reused for sequestration purposes. While onshore facilities are more homogeneous, offshore O&G operations are often significantly more tailored to a particular place, which might introduce additional engineering challenges associated with infrastructure reuse in general. If some parts of offshore infrastructure are available to be reused, it does not guarantee cost savings, but it is likely that the decision will need to be made on a case-by-case basis. Using our above framework, we estimate that the reuse of major pieces of offshore infrastructure for CO_2 sequestration might cost about US $313.8M (US $93.8M–$413.3M). However, different sources appear to be mixed as to the reliability of these estimates for a particular project. Figure 55 shows a sensitivity to major assumptions in the cost assessment of offshore infrastructure reuse.

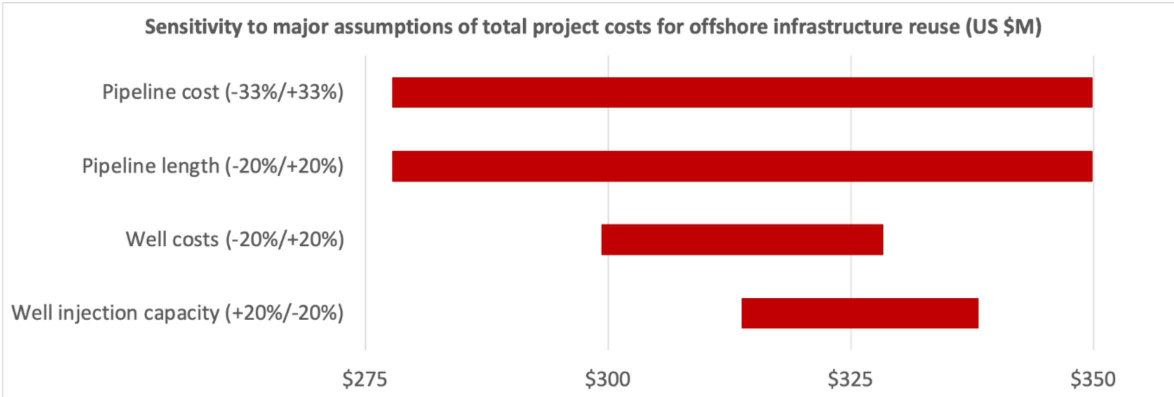

Figure 55: Sensitivity to cost assumptions for reuse of existing O&G infrastructure for offshore CCS (US $M).

5.8. Other elements to consider in new vs. reuse

One benefit of reusing existing infrastructure for CCS projects is that there is the potential for less disturbance to a given area, and thus could create the conditions for an easier social license to operate. A CCS project could simply be seen as an extension of what is already going on. In addition, given the fact that O&G projects have existed in a particular region in the past, the necessary services; site prep, well drilling, maintenance, etc., are likely to be in that area as well, which could result in lower costs.

5.9. Conclusions

This analysis cautions against the assumption that the reuse of existing O&G infrastructure will always, or even often, result in significant cost savings. Even if major portions of existing O&G infrastructure are reusable, there is still uncertainty as to if it will be useful for a CCS project. For example, a pipeline might be physically able to convey CO_2 to an existing or depleted field, but if it cannot handle the pressures needed to move the CO_2 at a supercritical state, additional compression or a new pipeline might be required. Existing onshore fields might have many wells that need remediation. While existing infrastructure has the potential to be useful and reduce costs, it is likely that each candidate location will require a site-specific assessment to determine its value.

5.10. Appendix 1: Comparison of major costs across scenarios

Pipeline length and well injection capacities are major drivers of our costs estimates for all four projects categories that we considered. Figure 46 to Figure 49 show each of our baseline assumption costs for a range of different estimates of the two drivers. Note that the 0.6 and the 0.8 Mtpa results are identical in each figure because each of those estimates results in the need for two wells to reach the project goal of 1 Mtpa injection.

For onshore (Figure 56 and Figure 57), the range of pipeline and well injection rates we considered had similar implications for the overall costs, i.e. for any given pipeline length, our estimated well injection capacity values changed the overall cost estimate by about US $20M. Interestingly enough, for any given well injection capacity (color of dots in the figures), the range in estimated pipeline lengths also varied the total estimated project cost by about US $20M. The impact of well injection capacity is more pronounced in the new infrastructure estimate, but less so in the infrastructure reuse estimate because the cost to workover an existing well is less than drilling a new one.

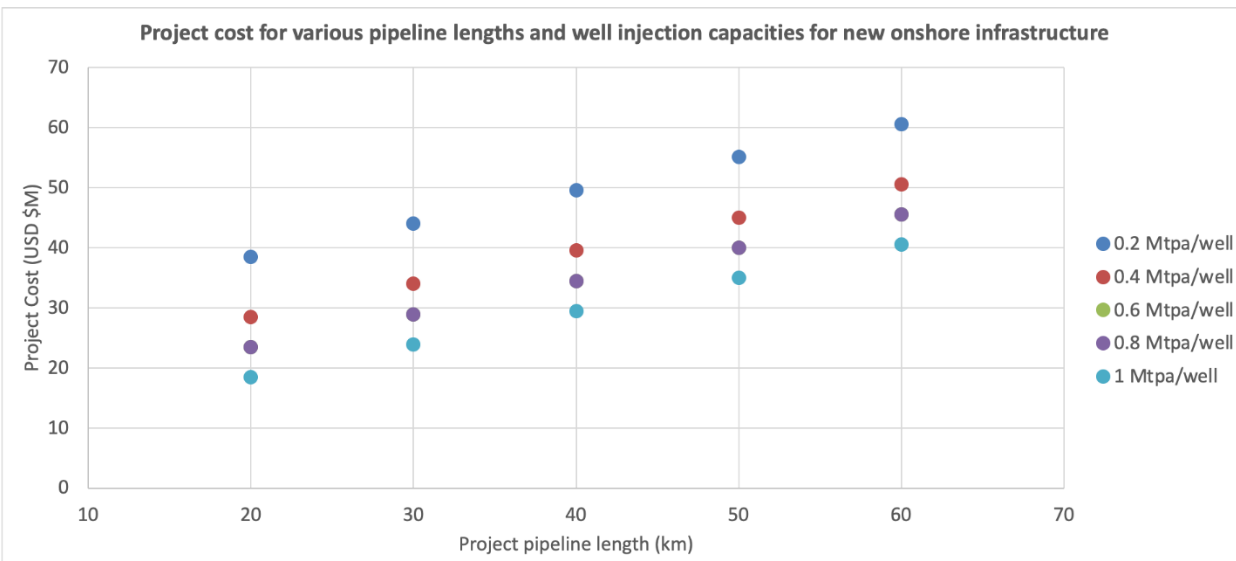

Figure 56: Project cost for various pipeline lengths and well injection capacities for new onshore infrastructure.

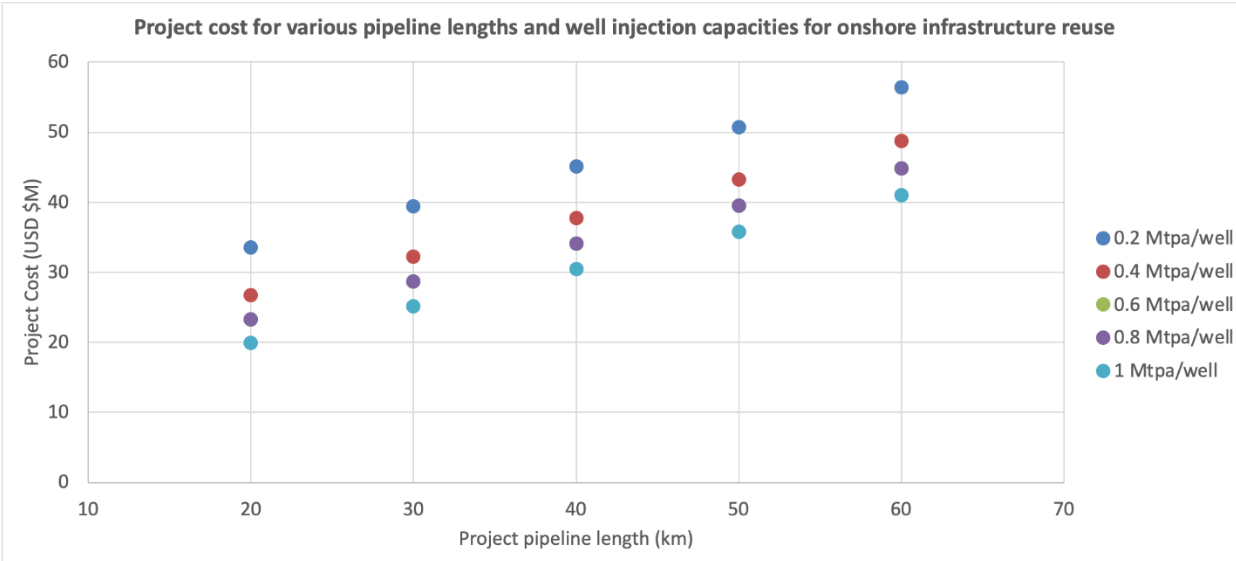

Figure 57: Project cost for various pipeline lengths and well injection capacities for reuse onshore infrastructure.

For new offshore projects (Figure 58), our estimates of differing pipeline length (20-60 km) change the overall project costs by approximately US $150M while our estimates in differing in well injection capacities alter costs by about US $200M. The change in so much so in that a single well were able to inject the required 1 Mtpa, we estimate that project would be cheaper, even including a 60km pipeline than a location that required a 20-km pipeline if the wells were only able to inject 0.2 Mtpa.

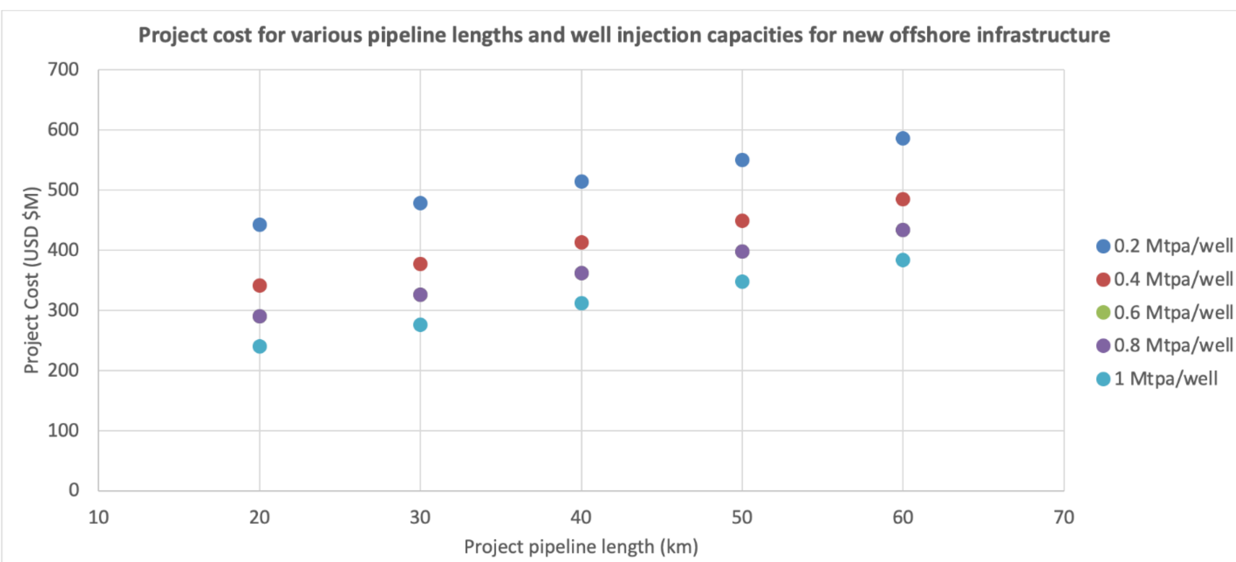

Figure 58: Project cost for various pipeline lengths and well injection capacities for new offshore infrastructure.

The same reasoning does not appear to hold for offshore infrastructure reuse (Figure 59) as even a project with the worst performing wells (0.2 Mtpa) that only needed a 20-km pipeline is estimated to be lower cost than the best performing wells at a greater distance (60km).

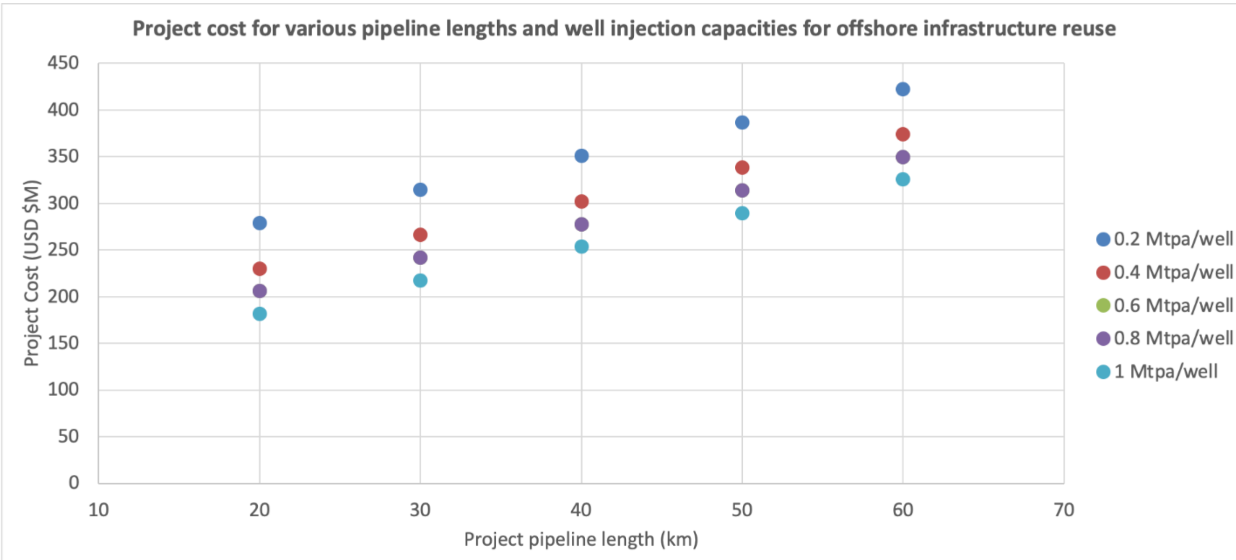

Figure 59: Project cost for various pipeline lengths and well injection capacities for reuse offshore infrastructure.

Overall, the choice between a new or reuse site is likely to be very project specific, with particular attention paid to pipeline distance and site well injection capacity. In general, new high-injection capacity wells close to the source of CO_2 are likely to be cheaper than existing low-injection capacity wells further away. However, for the same distance, existing infrastructure does appear to offer some cost savings.

6. Discussion

From the early days of CCS, depleted hydrocarbon fields have been considered as prospective and valuable CO_2 storage sites, and increasing interest in CCS drives an increased need for storage resources motivate this analysis. In many ways, the nascent industry of geologic carbon storage naturally follows the lead of the well-established petroleum industry. Even if the details differ, the basics of geology, subsurface characterization, risk assessment and engineering operations are similar and there are many decades of petroleum experience to learn from and adapt to new tasks. It is therefore tempting to frame exploration for storage in the mold of petroleum exploration, seeking to maximize the "favorable" parameters, with the implicit assumption that bigger is better. In petroleum exploration, that makes sense. Regardless of geographic location or company size, the bigger the discovered reserves, the bigger the potential pay-off. We would argue however, that that model makes less sense for CCS, at least at present.

In their current form, storage projects (CO_2-EOR excepted) are generally framed as efforts to mitigate a specific source of emissions. They are based around a specific geographic anchor point. Bigger is only better if it is within an economically reasonable distance from that source. Even then, bigger may not be better. A project to mitigate a 1-Mtpa source has no need of a gigaton-scale storage site. The goal of storing a certain volume of CO_2 from a specific source suggests reframing the question. Instead of defining favorable and unfavorable parameter ranges and seeking to maximize the number of "favorable," we suggest starting with the project requirements and asking which sites within a given distance might be good enough. Blanket statements about the value of existing infrastructure, the desirability of pressure depletion or nearly any other parameter inevitably fail when considering specific projects with a limited choice of potential storage sites. From the analysis presented here, we note that no single set of evaluation criteria will work for all projects. The net value of existing infrastructure is highly variable and the ability to repurpose it needs site-specific evaluation. Open reservoir boundaries offer greater capacity but closed ones may offer greater storage permanence. High-permeability reservoir offers good injectivity but might result in unacceptable plume spread. Remaining free gas in the reservoir reduces capacity but may improve long-term security by creating a buffer between stored CO_2 and the seal if gravity segregates the fluids in the reservoir, as some models suggest. A rusty 8" low-pressure pipeline might work for a project that plans limited CO_2 injection, with wellsite compression and a short project life. A bigger project with a need to keep compression close to the CO_2 source might consider the same pipeline a liability. Well penetrations create potential leak points in a proven seal but a field with 20 recent penetrations and good records might be preferable to one with two wells that were drilled 100 years ago and that no one can quite locate. In short, there is no single set of criteria that will work for all projects.

Instead, we would suggest framing evaluation as a project-specific process that considers both the sequestration requirements and the operator's metrics for success and views of acceptable risk. Depending on those, different storage site parameters will assume different priorities in ranking. Consider the following examples of geologic and economic success metrics and their key storage site characteristics:

- Maximum storage capacity: Favors a large field and thick, high-permeability reservoir with hydrostatic pressure and open boundaries. It will also create a large pressure footprint to monitor.

- Minimum containment risk: Favors a well-defined, pressure-depleted field with closed boundaries, a thick multi-layer top-seal and few legacy wells. These parameters however reduce the maximum injection rate and volume.
- Maximum profit: Depending on the business case, it might favor 1) a CO_2-EOR project with the dual revenue streams of storage and oil production; 2) high capacity and the ability to accept constant supply over many years; or 3) high injectivity pure storage (high rates to maximize net present value) and a project-specific balance of cost and capacity. Note that the downside of high injection rate is a potentially short project lifespan prior to exceeding maximum pressure (in the case of closed field boundaries) or pushing injected CO_2 beyond the field boundaries (in the case of open boundaries)
- Minimum development cost: Favors a short transport distance and/or reusable infrastructure. Possible trade-offs entirely dependent on the sites locally available and may include low injectivity and/or small capacity.

The definitions of "favorable" and "unfavorable" parameter ranges will inevitably diverge, as will the choices of available local sites. A government project to decarbonize an entire city might prioritize capacity, while setting minimum limits on injectivity and containment security. The operator of a single cement plant might prioritize minimum cost as long as small capacity and injectivity requirements could be met. A site need not be among the global "best" to be more than suitable for a specific project (see Appendix 1 for an attempt to quantify the trade-offs between economic and geologic metrics).

All fields are not equal though and we began this work with the goal of identifying criteria on which to evaluate them. Based on the case studies presented, we believe that regardless of an operator's success metrics, evaluation begins with five key headline criteria, each of which rests on a number of subsidiary factors:

- Injectivity: Can the proposed site accept injected CO_2 at the rates it is generated by the source(s)?
- Storage capacity: Does the proposed site have sufficient capacity to store the expected volume of CO_2 over the life of the project?
- Containment security: Can the proposed site be expected to retain the injected CO_2 a time scale sufficient to benefit the atmosphere? Are there redundant seals that would provide additional assurance or potential leak points of particular concern?
- Reusable infrastructure: Does the proposed site have infrastructure that can be repurposed for CCS and save development cost?
- Public acceptance and regulatory approval: Will the proposed site be acceptable to regulators and other stakeholders?

Each of these key factors depends on a complex combination of inputs which could be divided into individual ranges and described in terms of degrees of desirability. Indeed, such an approach is common in many fields and has been applied to screening for carbon storage sites (e.g., Raza et al., 2016). While this approach generally does a good job of identifying all of the inputs, the consideration of each one in isolation and the binary designation of "favorable" and "favorable" ranges misses important relationships and trade-offs between individual factors. What really matters for storage project is not the individual variables, but how they combine into the key headline parameters described above. Awareness of the inputs is important, but considering them in isolation misses the bigger picture. Instead we suggest the following approach, matching project requirements to the key integrated parameters listed.

6.1. Injectivity

As described, injectivity is a primary control on the sustainable injection rate for a given reservoir. Knowing the rate at which CO_2 will need to be stored (presumably similar to the rate of generation at the source), places a clear constraint on the reservoir injectivity required. It is proportional to the product of reservoir thickness and permeability. Thin reservoir may thus be compensated by high permeability and vice versa. Figure 60 shows the injectivity for supercritical CO_2 resulting from various combination of reservoir thickness and permeability. The diagonal lines give an indication of the injection rate (tons/year) achievable with supercritical CO_2 under equivalent multiples of thickness and permeability. A number of storage projects are plotted for reference, creating a useful screening tool for potential storage projects.

In detail, the achievable injection rate may be increased to some degree by engineering and operational factors, including the use of multiple and/or horizontal wells and increasing the injection pressure. The effect of horizontal wells can be approximated by changing the effective reservoir thickness to reflect the perforated length of the well in the reservoir. Both horizontal and multiple wells carry a cost implication and the wells must be located sufficiently far apart to mitigate undesirable pressure interactions. With increasing injection pressure, care must be taken not to exceed safe operating limits (as the example of In Salah shows). All of these considerations require project-specific evaluation. For screening, they should be considered as potential modifications to the injectivity but not as first-order controls.

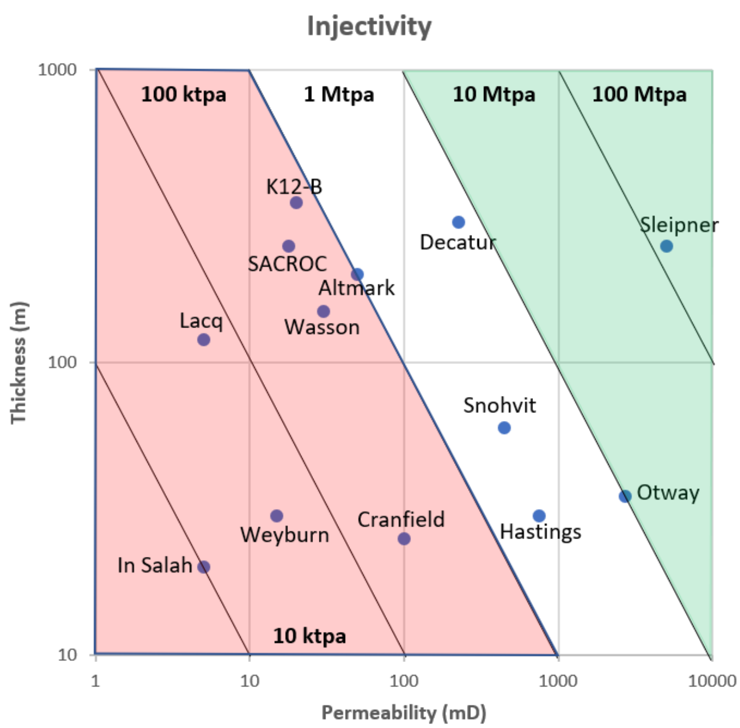

Figure 60: Plot of reservoir thickness vs. permeability showing order-of-magnitude injection rates per well for super-critical CO_2 in tons/year (Mtpa=megaton per annum, ktpa=kiloton per annum). Representative values for the case studies presented here, plus selected other storage projects are shown for reference. Note that the scale is logarithmic and that values shown are averages for the project. Individual well locations may show significant variability. Note also that effective reservoir thickness may be increased by using horizonal wells, as at In Salah, which used 1.5-km-long lateral segments in the reservoir to boost injectivity. Higher total injection rates may also be achieved by increasing the number of injection wells used. Background colors show suitability for commercial-scale storage projects (Hoffman et al., 2015). Data come from sources reported in the case studies and from Hosa et al. (2010).

6.2. Capacity

Capacity for geologic storage is a function of the accessible reservoir pore space, the difference between initial and final reservoir pressure, the final in-reservoir CO_2 density and the temperature and salinity of formation water. In detail, it depends on reservoir area, gross thickness, net to gross (N:G) porosity, the fraction of pore space accessible from the injector well(s), reservoir temperature, pore water salinity and the difference between initial reservoir pressure and a predetermined maximum acceptable geomechanical pressure limit (usually either virgin pressure, some fraction of fracture pressure of reservoir or seal, or a seismicity risk threshold). While it can be calculated from first principles, subsurface geologic uncertainty inevitably complicates the task. Depleted fields offer a powerful alternative: fluid replacement—the idea that a large fraction of the pore space once occupied by produced fluids can be re-occupied by injected fluids (~75% reoccupancy is a reasonable first guess; Jenkins et al., 2012). The simplest case is a field that has produced a single phase with no injection. If the cumulative production volume is known, it is a simple matter to calculate pore space occupied by that fluid at reservoir conditions and to create a prediction of the mass of CO_2 that could be stored in the accessible fraction of that pore space. The beauty of this approach is that it is specific to the field of interest and based on the observed performance of the field, including the impacts of reservoir heterogeneity and any other complicating factors. Figure 61 shows that prediction in graphical form for common case of post-production gas fields that have had no water injection. The relationship is based on detailed work on Gulf of Mexico fields and assumes that post-injection reservoir pressure will be equivalent to the virgin (pre-production) pressure.

Based on similar considerations, Figure 62 gives a predicted storage capacity for oil fields, based on net cumulative fluid production, defined as the sum of produced oil and water volumes minus the volume of injected water (Agartan et al., 2018). To be accurate, produced oil volumes must be corrected to reservoir volumes (i.e., surface oil volume should be multiplied by the formation volume factor). Formation volume factor (FVF) for oil is generally 1-2 and FVF for water is about 1, which means that water volumes need no correction for screening. Even without correction of oil volumes, the plot may still give a sufficient order-of-magnitude indication for screening potential storage capacities. As for the gas case, the prediction assumes that final pressure will be equal to virgin pressure. Figure 61 and Figure 62 gives a first-pass estimate of storage capacity in depleted gas fields that is more than sufficient for screening. The beauty of capacity estimation in a depleted field is that it relies on observed and generally available field production history and that it avoids much of the subsurface uncertainty that plagues calculation of capacity without production history. In addition, production history is very helpful in providing data to support the more detailed calculations ultimately be needed for project development,

Significant additional capacity can be accessed for both fields with open boundaries and those with closed boundaries if an operator is willing and able to raise reservoir pressure beyond the virgin (pre-production) value. More additional capacity may be available in fields with open lateral boundaries, as shown by the pressure modeling in this report. While the benefit of increased capacity is obvious, the cost for doing so is greater containment risk and/or larger footprint of the area of elevated pressure such that more evaluation will be needed to eliminate any possible leakage pathways. Raising pressure above virgin stresses the geologic containment elements beyond their proven effective limits and therefore requires careful evaluation. Similarly, open boundaries allow any pressure increase to propagate beyond the field boundaries, which may create a noticeable impact on neighboring fields or storage sites and therefore needs focused analysis. Even in the absence of neighbors, propagating pressure beyond the field boundaries creates a larger footprint to monitor and possibly increased monitoring costs.

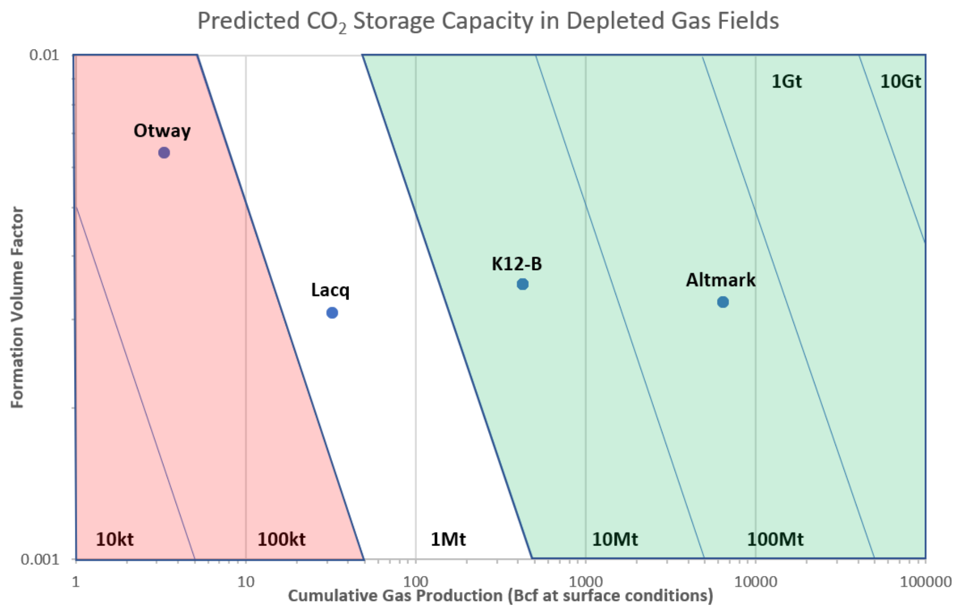

Figure 61: Predicted order-of-magnitude storage capacity for super-critical CO_2 injected into a depleted gas field. Prediction is based on the principle of reservoir fluid replacement using the relations derived by Agartan et al. (2018) for Gulf of Mexico fields. The plot assumes that methane is the predominant produced fluid and that there has been no water injection. Formation Volume Factor is the ratio of hydrocarbon gas volume at reservoir conditions to the same mass at surface conditions. The case studies presented here that fit these criteria are shown for reference. Background colors indicate suitability for industrial-scale storage projects. Note the logarithmic scales.

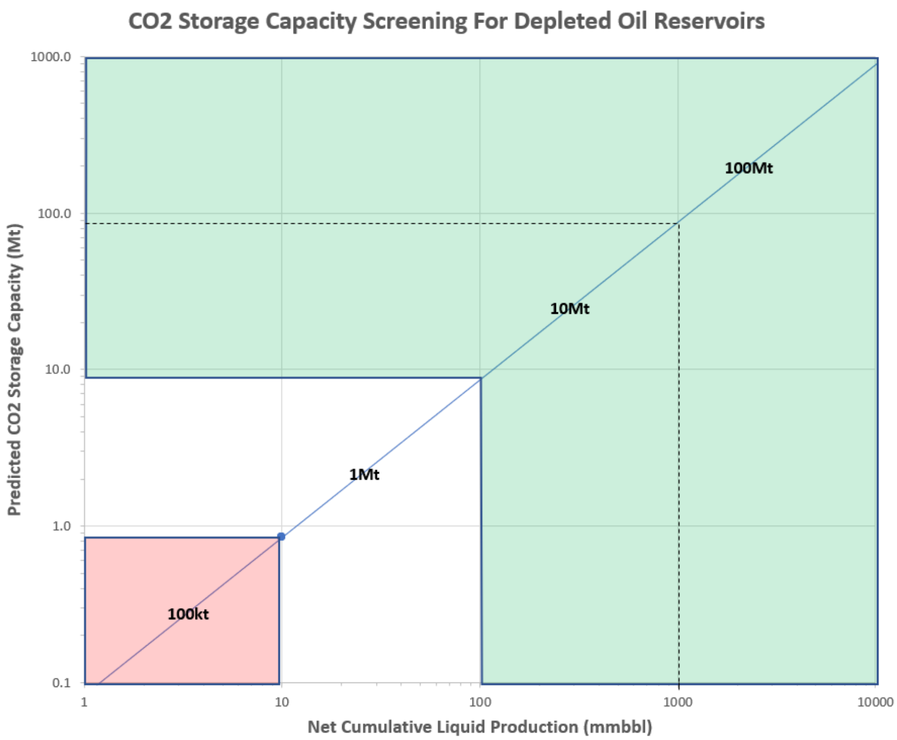

Figure 62: Predicted CO_2 storage capacity of depleted oil fields. The horizontal axis is net cumulative fluid production, defined as the sum of produced oil and water, minus injected water. Predicted storage capacity is based on the work of Agartan et al. (2018) and can be read off the vertical axis. Note that estimates will be most accurate if produced oil volumes are specified for reservoir conditions (surface volume multiplied by Formation Volume Factor, generally 1-2 for oil; water is effectively incompressible and correction can be neglected for screening purposes).

6.3. Containment security

Long-term containment security is critical to project success and to maintaining public trust in CCS. Depleted fields start with seals proven capable of retaining oil and gas over geologic time. We suggest starting with that observation and focusing on the factors that might compromise or enhance that security for stored CO_2. Potentially compromising factors include the change in fluid properties, legacy wells and excess injection pressure. Potentially enhancing factors include reduced pressure and multiple or layered seals. Considerations relating to each are detailed below and summarized in Table 8:

- Change in fluid type: With a seal proven for hydrocarbons, the first question is how that proven capacity applies to CO_2. Naylor et al found that maximum CO_2 column heights were typically 0.8-1.2 x pre-production gas column heights, where those gas columns were limited by top seal capacity (Naylor et al., 2011). The range arises from variations in capillary entry pressure and CO_2 density (buoyancy). Gas columns limited by spill point or charge volume indicate only minimum seal capacity. At the screening stage, observed gas column heights can be regarded as indicative of CO_2 column height capacity. By contrast, oil is a larger molecule than CO_2, with a consequently higher capillary entry pressure and is therefore less indicative of CO_2 storage security. If present, neighboring gas fields sealed by the same geologic unit would offer screening level assurance.

Otherwise a more thorough analysis of the sealing unit is required. Evidence of oil leakage through the top seal should be regarded as a warning against CO_2 storage.

- Legacy wells: Legacy wells are a known potential leak point and minimizing the number of legacy wells is a screening criterion. This generally favors gas fields over oil fields. The history and condition of the wells is also a screening criterion. Risk factors include poor records, a complex development and operational history, and many previously plugged and abandoned wells. If completion and plug and abandonment records are not available, the storage project will have to reenter, assess condition of external cement, mitigate, and replug. A complex development history can lead to mis-located wells, lost records, widely variable practices, and complex use of wells such as sidetracks, laterals, and non-standard completions and plugging practices. Older well construction is more variable and may not to as high standard as newer wells. In the US, well construction and abandonment regulations arose gradually on a state by state basis. The two key developments were the API codification of cementing practices by the early 1950s and the tightening of regulations following passage of the federal Safe Drinking Water Act in 1974 (NPC, 2011). If wells are still open, the cost of reentry for cement assessment is lower than if the wells have been plugged however, plugging cost will be needed to prepare the field for storage which generally requires fewer wells then production.
- Increasing pressure: The presence of a hydrocarbon accumulation proves the integrity of containment up to virgin pressure. If injection-related reservoir pressure is going to exceed that value, we suggest analysis of the seal capacity and stability of any faults required for containment. Some reservoirs may have been geomechanically damaged during strong depletion. If there is evidence of production-related geomechanical damage (e.g., reservoir compaction; Nagel, 2001; Jimenez and Chalaturnyk, 2003), then careful analysis is also advised.
- Layered or multiple seals: Layered or multiple sealing intervals offer additional security by creating redundancy. If CO_2 or pressurized brine escapes the primary seal, the intervening permeable intervals create opportunities to bleed off both and retard any fracture growth. For assurance of containment security, layered seals or multiple sealing intervals are clearly desirable.

6.4. Reusable infrastructure

Although it seems intuitively obvious that existing infrastructure should save on storage project development costs, the analysis presented here shows that not all infrastructure is reusable and that the cost of remediating large numbers of legacy wells and/or modifying existing platforms or pipelines may completely offset costs saved elsewhere. Noting that pipelines and platforms are by far the largest costs, we suggest focusing screening criteria on whether these elements will be re-usable. For pipelines, the key questions are capacity, pressure rating and remaining service life. Capacity requirements are project-specific but for reference, a 10-inch diameter pipeline is capable of transporting 1 Mtpa of supercritical CO_2 (IEAGHG, 2014). Pipeline capacity is proportional to its cross-sectional area, so screening thresholds can be easily adjusted for individual projects (doubling the diameter increases capacity by 4X). The pressure required to transmit CO_2 in a supercritical state at surface temperatures is between 82 and 150 bars (8.2–15 MPa), which suggests screening for a minimum pressure rating of 82 bars and a desirable rating of 150 bars (Table 8). As noted, lower pressure pipelines can be used to transmit CO_2 in a gas phase but require larger diameter to achieve the same yearly capacity and would require wellsite compression to inject CO_2 in a supercritical phase, hence are more suitable for small volume projects. Last, any pipeline under consideration for re-use must have sufficient mechanical integrity to safely cover the lifespan of the project. Although individual review and inspection would be needed prior to recommissioning a pipeline for CO_2 transport, remaining service life (or in-service date) can be used as a screening-level indication. In the US Gulf of Mexico, currently active pipelines were placed in service as early as 1955 (i.e., ~65 years of service to date) and service lifetimes of up to 85 years can be expected in some cases (Dombrowski et al., 2021). Newer is clearly better and specifics may vary regionally, but we suggest screening for pipelines placed into service after 1980 and preferably after 2000.

Platform re-usability seems even more dependent on specific project requirements than pipelines. If additional compression or heating equipment is required, then screening for platforms with the topside space to add such equipment seems reasonable. Even platforms without topside space could potentially add subsea facilities (at additional cost). Perhaps the most universally useful screening criterion for platforms is simply remaining service life. Similar to pipelines, the specifics may vary regionally but we suggest starting by screening for platforms placed into service after 1980 and preferably after 2000. The cost of decommissioning can be considered in the overall cost estimation and favors reuse.

Last, it is worth considering the value of data in depleted fields. All depleted fields will come with at least some well logs and production history. Many will come with detailed log suites, extensive production records and 3D seismic surveys. These are of tremendous value in characterizing the field for CO_2 storage, for planning monitoring and for creating and history-matching reservoir models. While missing data can be reacquired (with the exception of operational records), having it saves time and expense. Therefore, we suggest that screening favor fields without major data gaps.

6.5. Regulatory approval and public acceptance

As illustrated by the case studies described here, there are pronounced differences in public and regulatory acceptance of CCS between countries and between communities. Beyond the broad observations that current attitudes favor CO_2-EOR in the US and pure storage in Europe, it is difficult to create broadly applicable screening criteria. Noting the potential for otherwise promising projects to be delayed or abandoned in the face of regulatory or public opposition however, we strongly support the widespread recommendation of very early engagement with regulators and community leaders in regions under consideration. These early conversations may uncover clear regional differences or local considerations that need to be addressed. Both may create critical regionally applicable screening criteria and both may save considerable time, effort and cost in project development.

	Consideration	Screening Threshold: Desirable	Screening Threshold: Suggested boundary condition	Notes
Subsurface parameters for storage	Depth	> ~800-1000m	below lowest local fresh water aquifers	CO2 must be stored below fresh water aquifers and it is highly desireable to store it in a dense phase (depth depends on reservoir temperature and pressure, but is generally >800-1000m). Additional depth offers potential additional security
	Reservoir pressure	<< hydrostatic	not greater than hydrostatic	
	Capacity	25-50% > project requirements	project requirements	See graph for estimated capacity based on produced volumes; Excess capacity adds a margin of safety. Note also that fields with open boundaries may offer extra capacity.
	Injectivity	25-50% > project requirements	project requirements	See graph for estimated values; note that injection rate can also be raised by employing more injection wells and/or horizontal wells, at the expense of cost
Subsurface parameters for CO_2-EOR	Cumulative production	> 100mmbbl	> 1mmbbl	A proxy for remaining reserves. Thresholds may be project-specific but bigger is generally more desirable
	Reservoir pressure		> MMP, <80% fracture pressure	If local Minimum Miscibility Pressure (MMP) is unknown, a minimum depth of 6000ft (1800m) may be used instead
	Production stage	on secondary recovery	no pressure support from injection or natural water drive	
	Geologic complexity	low	moderate	stratigraphic and structural complexity
Containment Security	Top seal capacity	virgin gas column limited by spill	Seal-limited hydrocarbon columns	
	Top seal character	layered topseal or muliple sealing intervals a	No evidence of hydrocarbon leakage	
	Number of legacy wells	< 5	< 20	There is no hard rule. The more legacy wells, the greater the cost to review and potentially remediate them
	Age of oldest legacy well	younger than 1980	avoid older than 1955	Check the history of local P&A regulations for watershed dates. The dates given are based on US practice
	Well construction records	complete records and CBLs	avoid P&A'd wells with major data gaps	
Infrastructure	Current status	in active service, near end of field life	not yet decommissioned	
	Pipeline diameter	project-specific	>10" (25cm)	pipeline capacity is proportional to cross-sectional area; 10" is sufficient to carry 1 Mtpa supercritical CO_2
	Pipeline pressure rating	>150 bar (15MPa)	>82 bar (8.2MPa)	note that lower pressure ratings can be used at the expense of needing injection-site compression
	Pipeline in-service date	>2000	>1980	Check local specifications on design life and adjust screening thresholds such that remaining service life will cover the storage project
	Platform in-service date	>2000	>1980	
	Platform topside space	project-specific		Depends on project heating and compression needs. Subsea solutions may also be available for additional cost
	Production history data 3D seismic data Well log data	complete, accessible, high-quality data	Avoid major data gaps	Well logs and seismic data can be re-acquired at additional cost; production history is irreplaceable but unlikely to be completely missing
Public Acceptance & Regulatory Approval	Local precedent	Local projects successfully in operation	Previous local CCS proposals rejected	Engage early and identify regional differences and key considerations
	Regulatory readiness for CCS	Complete legal framework in place	Local regulators willing to address gaps	
	Local public attitude toward CCS	Accepting of or enthusiastic about CCS	Not actively opposed	

Table 8: Suggested screening parameters for depleted fields. Criteria for CO_2-EOR screening are taken from Núñez-López et al. (2008). Other sources are as cited in the text.

The best scenarios might actually be hybrids that blur the line between hydrocarbon production and CO_2 storage and between depleted fields and saline aquifers. Such scenarios include CO_2-EOR and injection into the water leg down-dip of a depleted reservoir.

CO_2-EOR is in some ways a sweet spot. It offers a dual income stream, the data record of a producing field, potentially greater storage efficiency (Alfi and Hosseini, 2016), mature permitting and regulation the ability to balance injection and production and therefore maintain reservoir pressure and even control the migration of the CO_2 plume (González-Nicolás et al., 2019). To be viable for CO_2-EOR, candidate fields need to meet requirements for minimum miscibility (pressure temperature and oil density) and should already be on secondary recovery. Ideally, a candidate field would also have good reservoir quality low structural or stratigraphic complexity and therefore good potential for high CO_2 sweep efficiency (Núñez-López et al., 2008). There is also a minimum reserve size that will be economically viable CO_2-EOR. Núñez-López et al. (2008) used 1 mmbbl in cumulative production as a screening proxy for viable quantities of remaining reserves. Depending on local specifics (e.g., onshore vs. offshore, availability of CO_2, etc.), that threshold may vary significantly. Fields that pass those filters however, create additional options for storage that may be very attractive. A second income stream might appeal to operators looking to maximize profit. Similarly, the ability to manage pressure by balancing injection and production might appeal to those looking from minimum risk (González-Nicolás et al., 2019). Perhaps most intriguingly, CO_2-EOR projects offer the prospect of a different success metric: Permitting time and chance of public acceptance. As the case studies showed, permitting and regulation for CO_2-EOR is mature and may offer a far faster path to operation than pure storage, at least in the US.

Similarly, injection down-dip of a depleted field offers many of the same benefits as injection straight into the field, plus potential advantages. Injecting down dip of the trap, on the migration path but well outside of the closure (perhaps kilometers outside) offers the chance for increased capacity, possibly better injectivity, stand-off from legacy wells and a proven trap at the end of the migration path. Locating the injector down-dip of the hydrocarbon-water contact offers a large potential range of sites and therefore gives greater flexibility to find and target high-injectivity reservoir facies. As the injected CO_2 migrates up-dip toward the trap, pore throat trapping, dissolution and retention in any small buoyant traps encountered all add to the storage capacity. CO_2 that does not get trapped during migration ends up in the depleted field with a proven seal. Last, injection pressure dissipates with distance from the injection well. If legacy wells are located within the bounds of the depleted field, injecting down-dip give greater stand-off from those wells and may reduce leakage risk.

Along with success criteria and evaluation of the storage capacity, injectivity, security, infrastructure and regulatory/public acceptance, it is worth looking at the potential risks to success, the factors that could completely derail the project. The case studies presented here offer some insight and a broader look at industry suggests others. They include:

- Mismatched reservoir injectivity and CO_2 production rate. If reservoir injectivity is too low to receive incoming CO_2 at the rate it is produced (e.g., White et al., 2018), the operator is left with three potentially unattractive options. First, the operator can drill more wells (or add horizontal sections to existing ones), increasing cost and risking project economics. Second, injection pressure can be increased, risking loss of containment if the seal is fractured. Third, excess CO_2 can be sent elsewhere or vented to the atmosphere.

- Mismatched reservoir capacity and injection rate. Thick, high-permeability reservoirs may easily accept CO_2 at commensurately high injection rates but spillage is possible if the field edges are too close to the point of injection. A modelling study of storage potential in the Forties oil field found that the reservoir could accept injection rates up to 5 Mtpa from a single well. However, at rates greater than 3 Mtpa, CO_2 tended to spill from the field under its own momentum (Babaei et al., 2014).
- Public acceptance. Despite its technological maturity, the practice of geologic carbon storage is young and public acceptance is not a given. The projects have made serious and sustained efforts to share their plans, listen to public concerns and address any issues (Ha-Duong et al., 2010; Cook, 2017). Even so, not all were successful and as Altmark illustrates, public opposition can scuttle permitting campaigns (Kuhn et al., 2012; Dütschke et al., 2015).
- Induced seismicity. Injection-related seismicity has not yet been a factor in CCS projects but it could become one. Raising fluid pressure on critically stressed faults has the potential to cause slip and potentially, leakage of CO_2 (Zoback and Gorelick, 2012, 2015). Such an event could damage public trust and continued permission to operate at the site in question and others globally.

While all of these risks are cautionary points and should be considered during project assessment, they can generally be mitigated with careful project design.

7. Conclusion

In summary, CO_2 storage in depleted fields encompasses a broad spectrum, ranging from storage within the field after the end of production, to syn-production injection into the water leg, syn-production injection into the field, and CO_2-EOR. The case studies presented here offer insight into the science and practice of storage in depleted fields. They confirm the science of storage and provide case examples of successful monitoring approaches. They also illustrate the major hurdles facing such projects and the disparities in permitting and public acceptance between CO_2-EOR and pure storage in depleted fields. Despite being technically similar, they have been regarded very differently by regulators and the public.

The initial pressure state of a depleted field is in part a reflection of boundary conditions and the connection between the hydrocarbon reservoir and a larger aquifer. Pressure-depleted fields offer greater latitude for injection-related pressure increase but are pressure depleted in part because they have closed or semi-closed boundaries. Numerical modelling experiments show that the increased capacity gained from pressure depletion is less by a factor of 10 than the capacity of a hydrostatically-pressured field with open boundaries. Arguments favoring pressure-depleted fields include that the capacity is sufficient to the project scale and high security for the relatively smaller volumes but the decreased capacity must be recognized.

The fraction of residual methane has a small effect on CO_2 storage capacity and injectivity. Higher residual methane values negatively affect CO_2 residual and solubility trapping efficiency, while hydrocarbon gas mixing with the injected CO_2 plume increases the plume mobility in the vicinity of injector, leading to an enhancement in the injectivity and pressure management in the reservoir.

Inherited infrastructure is often regarded as a positive for potential storage projects. However, it should not be taken as guaranteed that infrastructure reuse will always result in lower costs for CCS projects. A closer look shows that infrastructure is often not reusable, due to differing design specifications for hydrocarbon production and CO_2 storage. Where new infrastructure is required, pipeline costs are the biggest driver of total project costs and capital costs for offshore projects are roughly an order of magnitude higher than onshore costs for the same size project.

With regard to evaluating depleted fields, there is no single set of criteria that fit all situations. The key factors to consider are storage capacity, reservoir injectivity containment security, potential for infrastructure reuse and the risks to regulatory approval and public acceptance. Each of these rests on a number of subsidiary factors and similar headline results can be achieved with variable mixes of inputs. The key is that these headlines match the requirements of the project. The relative importance of each will depend on the operator's individual metrics for success but we have identified the key criteria for efficiently screening depleted fields for storage CO_2-EOR offers a potentially attractive alternative to pure storage as it can accept and retain large volumes of CO_2 but benefits from an additional income stream and mature regulation in some parts of the world. Injecting down-dip of a depleted field and letting migrate into it may also offer some benefits, including enhanced capacity and reduced pressure on potential leak points.

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